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Presidential Documents

Title 3—

The President

Executive Order 13707 of September 15, 2015

Using Behavioral Science Insights To Better Serve the American People

A growing body of evidence demonstrates that behavioral science insights—research findings from fields such as behavioral economics and psychology about how people make decisions and act on them—can be used to design government policies to better serve the American people.

Where Federal policies have been designed to reflect behavioral science insights, they have substantially improved outcomes for the individuals, families, communities, and businesses those policies serve. For example, automatic enrollment and automatic escalation in retirement savings plans have made it easier to save for the future, and have helped Americans accumulate billions of dollars in additional retirement savings. Similarly, streamlining the application process for Federal financial aid has made college more financially accessible for millions of students.

To more fully realize the benefits of behavioral insights and deliver better results at a lower cost for the American people, the Federal Government should design its policies and programs to reflect our best understanding of how people engage with, participate in, use, and respond to those policies and programs. By improving the effectiveness and efficiency of Government, behavioral science insights can support a range of national priorities, including helping workers to find better jobs; enabling Americans to lead longer, healthier lives; improving access to educational opportunities and support for success in school; and accelerating the transition to a low-carbon economy.

NOW, THEREFORE, by the authority vested in me as President by the Constitution and the laws of the United States, I hereby direct the following:

Section 1. *Behavioral Science Insights Policy Directive.*

(a) Executive departments and agencies (agencies) are encouraged to:

(i) identify policies, programs, and operations where applying behavioral science insights may yield substantial improvements in public welfare, program outcomes, and program cost effectiveness;

(ii) develop strategies for applying behavioral science insights to programs and, where possible, rigorously test and evaluate the impact of these insights;

(iii) recruit behavioral science experts to join the Federal Government as necessary to achieve the goals of this directive; and

(iv) strengthen agency relationships with the research community to better use empirical findings from the behavioral sciences.

(b) In implementing the policy directives in section (a), agencies shall:

(i) identify opportunities to help qualifying individuals, families, communities, and businesses access public programs and benefits by, as appropriate, streamlining processes that may otherwise limit or delay participation—for example, removing administrative hurdles, shortening wait times, and simplifying forms;

(ii) improve how information is presented to consumers, borrowers, program beneficiaries, and other individuals, whether as directly conveyed by the agency, or in setting standards for the presentation of information, by considering how the content, format, timing, and medium by which information is conveyed affects comprehension and action by individuals, as appropriate;

(iii) identify programs that offer choices and carefully consider how the presentation and structure of those choices, including the order, number, and arrangement of options, can most effectively promote public welfare, as appropriate, giving particular consideration to the selection and setting of default options; and

(iv) review elements of their policies and programs that are designed to encourage or make it easier for Americans to take specific actions, such as saving for retirement or completing education programs. In doing so, agencies shall consider how the timing, frequency, presentation, and labeling of benefits, taxes, subsidies, and other incentives can more effectively and efficiently promote those actions, as appropriate. Particular attention should be paid to opportunities to use nonfinancial incentives.

(c) For policies with a regulatory component, agencies are encouraged to combine this behavioral science insights policy directive with their ongoing review of existing significant regulations to identify and reduce regulatory burdens, as appropriate and consistent with Executive Order 13563 of January 18, 2011 (Improving Regulation and Regulatory Review), and Executive Order 13610 of May 10, 2012 (Identifying and Reducing Regulatory Burdens).

Sec. 2. *Implementation of the Behavioral Science Insights Policy Directive.* (a) The Social and Behavioral Sciences Team (SBST), under the National Science and Technology Council (NSTC) and chaired by the Assistant to the President for Science and Technology, shall provide agencies with advice and policy guidance to help them execute the policy objectives outlined in section 1 of this order, as appropriate.

(b) The NSTC shall release a yearly report summarizing agency implementation of section 1 of this order each year until 2019. Member agencies of the SBST are expected to contribute to this report.

(c) To help execute the policy directive set forth in section 1 of this order, the Chair of the SBST shall, within 45 days of the date of this order and thereafter as necessary, issue guidance to assist agencies in implementing this order.

Sec. 3. *General Provisions.* (a) Nothing in this order shall be construed to impair or otherwise affect:

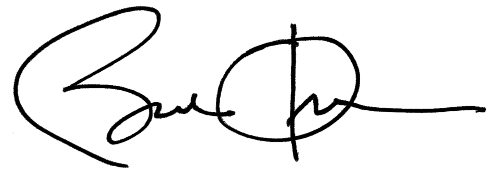
(i) the authority granted by law to a department or agency, or the head thereof; or

(ii) the functions of the Director of the Office of Management and Budget relating to budgetary, administrative, or legislative proposals.

(b) This order shall be implemented consistent with applicable law and subject to the availability of appropriations.

(c) Independent agencies are strongly encouraged to comply with the requirements of this order.

(d) This order is not intended to, and does not, create any right or benefit, substantive or procedural, enforceable at law or in equity by any party against the United States, its departments, agencies, or entities, its officers, employees, or agents, or any other person.



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Rules and Regulations

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DEPARTMENT OF COMMERCE

Bureau of Industry and Security

15 CFR Part 774

[Docket No. 141229999–5828–02]

RIN 0694–AG45

Implementation of the Australia Group (AG) November 2013 Intersessional Decisions; Correction

AGENCY: Bureau of Industry and Security, Commerce.

ACTION: Correcting amendments.

SUMMARY: The Bureau of Industry and Security (BIS) publishes this final rule to correct typographical errors contained in a final rule published on June 16, 2015 (80 FR 34266), which amended the Export Administration Regulations (EAR) to implement the recommendations presented at the November 2013 Australia Group (AG) intersessional implementation meeting and later adopted pursuant to the AG silent approval procedure. The typographical errors appear in a Note to ECCN 1C351.a, which includes viruses identified on the AG ''List of Human and Animal Pathogens and Toxins for Export Control.'' This rule also identifies another typographical error in the June 16, 2015, final rule involving the ''*Reason for Control*'' paragraph for ECCN 1E351. This error does not require a correction at this time, but is being identified to provide clarification to the public.

DATES: This rule is effective September 18, 2015.

FOR FURTHER INFORMATION CONTACT: Richard P. Duncan, Ph.D., Director, Chemical and Biological Controls Division, Office of Nonproliferation and Treaty Compliance, Bureau of Industry and Security, Telephone: (202) 482–3343, Email: *Richard.Duncan@bis.doc.gov.*

SUPPLEMENTARY INFORMATION:

On June 16, 2015, the Bureau of Industry and Security (BIS) published the final rule ''Implementation of the Australia Group (AG) November 2013 Intersessional Decisions'' (80 FR 34266), which amended the Export Administration Regulations (EAR) to reflect the merger of two AG common control lists by removing ECCN 1C352 (animal pathogens) from the CCL and adding the pathogens previously controlled under ECCN 1C352 to ECCN 1C351 (human and zoonotic pathogens and ''toxins''). The latter ECCN was renamed to indicate that it controls both human and animal pathogens and ''toxins.'' That final rule also renumbered the items in ECCN 1C351.a, and certain items in ECCN 1C351.c to accommodate the addition to ECCN 1C351 of those items that had been controlled under ECCN 1C352 prior to the publication of that rule.

As amended by the June 16, 2015, final rule, the Note to ECCN 1C351.a.4 (which controls avian influenza viruses identified as having high pathogenicity) incorrectly referenced ECCN 1C352.a.4, instead of ECCN 1C351.a.4. This final rule corrects the references contained in that Note. Specifically, the Note to ECCN 1C351.a.4 is corrected to read as follows: ''*Avian influenza (AI) viruses of the H5 or H7 subtype that do not have either of the characteristics described in 1C351.a.4 (specifically, 1C351.a.4.a or a.4.b) should be sequenced to determine whether multiple basic amino acids are present at the cleavage site of the haemagglutinin molecule (HA0). If the amino acid motif is similar to that observed for other HPAI isolates, then the isolate being tested should be considered as HPAI and the virus is controlled under 1C351.a.4.*'' The corrections to this Note do not affect the scope of the controls described in ECCN 1C351.a.4.

In addition, the text for ECCN 1E351, as published in the June 16, 2015, final rule incorrectly identified the applicable controls for this ECCN under the ''*Reason for Control*'' paragraph in the License Requirements section. Specifically, the ''*Reason for Control*'' paragraph mistakenly identified the applicable controls for ECCN 1E351 as ''NS, MT, NP, CB, RS, AT,'' instead of ''CB, AT.'' It is not necessary, however, to amend ECCN 1E351 to correct this error, because the amendatory instructions for ECCN 1E351 in the June 16, 2015, final rule did not include a specific instruction to amend the ''*Reason for Control*'' paragraph for this ECCN. Consequently, the ''*Reason for Control*'' paragraph in ECCN 1E351 was not revised by the June 16, 2015, final rule. The paragraph, as published in the CCL, continues to correctly identify the applicable controls for this ECCN as ''CB, AT.'' BIS identifies this error to inform the public of the inconsistency between the contents of the June 16, 2015, final rule and the CCL, and to provide clarification regarding the applicable controls for ECCN 1E351.

Although the Export Administration Act expired on August 20, 2001, the President, through Executive Order 13222 of August 17, 2001, 3 CFR, 2001 Comp., p. 783 (2002), as amended by Executive Order 13637 of March 8, 2013, 78 FR 16129 (March 13, 2013), and as extended by the Notice of August 7, 2015 (80 FR 48,233 (Aug. 11, 2015)), has continued the Export Administration Regulations in effect under the International Emergency Economic Powers Act. BIS continues to carry out the provisions of the Export Administration Act, as appropriate and to the extent permitted by law, pursuant to Executive Order 13222, as amended by Executive Order 13637.

Rulemaking Requirements

1. Executive Orders 13563 and 12866 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. This rule has been determined to be not significant for purposes of Executive Order 12866.

2. Notwithstanding any other provision of law, no person is required to respond to, nor shall any person be subject to a penalty for failure to comply with, a collection of information subject to the requirements of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*) (PRA), unless that collection of information displays a currently valid

Office of Management and Budget (OMB) Control Number. This rule contains a collection of information subject to the requirements of the PRA. This collection has been approved by OMB under Control Number 0694–0088 (Multi-Purpose Application), which carries a burden hour estimate of 58 minutes to prepare and submit form BIS–748. Send comments regarding this burden estimate or any other aspect of this collection of information, including suggestions for reducing the burden, to Jasmeet Seehra, Office of Management and Budget (OMB), and to the Regulatory Policy Division, Bureau of Industry and Security, Department of Commerce, 14th Street & Pennsylvania Avenue NW., Room 2705, Washington, DC 20230.

3. This rule does not contain policies with Federalism implications as that term is defined in Executive Order 13132.

4. The provisions of the Administrative Procedure Act (5 U.S.C. 553) requiring notice of proposed rulemaking and the opportunity for public participation are waived for good cause because they are unnecessary and contrary to the public interest. (See 5 U.S.C. 553(b)(B)). The changes contained in this rule are non-substantive technical corrections of a previously published rule that has already been exempted from notice and comment. This rule is necessary to ensure clarity in the regulations and accuracy regarding the scope of controls in the Note to ECCN 1C351.a.4. If this rule were delayed to allow for notice and comment, it would result in further confusion caused by the incorrect cross-references in that ECCN. These changes are also essential to ensuring the accurate and complete implementation of the June 16, 2015, final rule.

The provision of the Administrative Procedure Act (5 U.S.C. 553) requiring a 30-day delay in effectiveness is also waived for good cause. (5 U.S.C. 553(d)(3)). The corrections contained in this final rule are non-substantive technical corrections of a previously published rule that has already been exempted from notice and comment. If this rule were delayed to allow for a 30-day delay in effectiveness, it would result in further confusion caused by the incorrect cross-references in the aforementioned ECCN. These changes are also essential to ensuring the accurate and complete implementation of the June 16, 2015, final rule.

Further, no other law requires that a notice of proposed rulemaking and an opportunity for public comment be given for this final rule. Because a notice of proposed rulemaking and an opportunity for public comment are not required to be given for this rule under the Administrative Procedure Act or by any other law, the analytical requirements of the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*) are not applicable. Therefore, this regulation is issued in final form.

List of Subjects in 15 CFR Part 774

Exports, Reporting and recordkeeping requirements.

For the reasons stated in the preamble, part 774 of the Export Administration Regulations (15 CFR parts 730–774) is amended as follows:

PART 774—[AMENDED]

■ 1. The authority citation for 15 CFR part 774 continues to read as follows:

Authority: 50 U.S.C. app. 2401 *et seq.;* 50 U.S.C. 1701 *et seq.;* 10 U.S.C. 7420; 10 U.S.C. 7430(e); 22 U.S.C. 287c, 22 U.S.C. 3201 *et seq.;* 22 U.S.C. 6004; 30 U.S.C. 185(s), 185(u); 42 U.S.C. 2139a; 42 U.S.C. 6212; 43 U.S.C. 1354; 15 U.S.C. 1824a; 50 U.S.C. app. 5; 22 U.S.C. 7201 *et seq.;* 22 U.S.C. 7210; E.O. 13026, 61 FR 58767, 3 CFR, 1996 Comp., p. 228; E.O. 13222, 66 FR 44025, 3 CFR, 2001 Comp., p. 783; Notice of August 7, 2015 (80 FR 48233 (Aug. 11, 2015)).

■ 2. In Supplement No. 1 to Part 774 (the Commerce Control List), Category 1— Special Materials and Related Equipment, Chemicals, ''Microorganisms'' and ''Toxins,'' ECCN 1C351 is amended under the ''*Items*'' paragraph in the List of Items Controlled section by revising the Note immediately following paragraph a.4.b to read as follows:

Supplement No. 1 to Part 774—the Commerce Control List

* * * * *

1C351 Human and animal pathogens and ''toxins'', as follows (see List of Items Controlled).

* * * * *

List of Items Controlled

* * * * *

Items:

a. * * *

a.4. * * *

a.4.b. * * *

Note: Avian influenza (AI) viruses of the H5 or H7 subtype that do not have either of the characteristics described in 1C351.a.4 (specifically, 1C351.a.4.a or a.4.b) should be sequenced to determine whether multiple basic amino acids are present at the cleavage site of the haemagglutinin molecule (HA0). If the amino acid motif is similar to that observed for other HPAI isolates, then the isolate being tested should be considered as HPAI and the virus is controlled under 1C351.a.4.

* * * * *

Dated: September 10, 2015.

Karen H. Nies-Vogel,

Director, Office of Exporter Services.

[FR Doc. 2015–23500 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–33–P

DEPARTMENT OF HOMELAND SECURITY

U.S. Customs and Border Protection

DEPARTMENT OF THE TREASURY

19 CFR Parts 133 and 151

[Docket No. USCBP–2012–0011; CBP Dec. 15–12]

RIN 1515–AD87

Disclosure of Information for Certain Intellectual Property Rights Enforced at the Border

AGENCIES: U.S. Customs and Border Protection, Department of Homeland Security; Department of the Treasury.

ACTION: Final rule.

SUMMARY: This document adopts as a final rule, with changes, interim amendments to the U.S. Customs and Border Protection (CBP) regulations pertaining to importations of merchandise bearing suspected counterfeit trademarks or trade names that are recorded with CBP. Specifically, the amendments allow CBP, for the purpose of obtaining assistance in determining whether merchandise bears a counterfeit mark, to disclose to a trademark or other mark owner information appearing on merchandise or its retail packaging that may otherwise be protected by the Trade Secrets Act. This final rule also amends the CBP regulations to further enhance information-sharing procedures by requiring CBP to release to the importer an unredacted sample or image of the suspect merchandise or its retail packaging any time after presentation of the suspect goods for examination. This change is to reflect that an importer may not have complete information about the marks appearing on imported goods, and release of such unredacted information will assist the importer in providing CBP with a meaningful response to a detention notice. The amendments in this final rule also require CBP to release limited importation information to the mark owner no later than the time of issuance of the detention notice to the importer, rather than within 30 business days from the date of detention. Finally, these amendments require CBP to notify the mark owner that use of any

information otherwise protected by the Trade Secrets Act that is disclosed by CBP to the mark owner is for the limited purpose of assisting CBP.

DATES: Effective on October 19, 2015.

FOR FURTHER INFORMATION CONTACT: Goli Gharib, Intellectual Property Rights Branch, Regulations and Rulings, Office of International Trade, (202) 325–0216.

SUPPLEMENTARY INFORMATION:

Background

On April 24, 2012, CBP published CBP Dec. 12–10 in the **Federal Register** (77 FR 24375), setting forth interim amendments to the CBP regulations that pertain to importations of merchandise bearing suspected counterfeit trademarks or trade names that are recorded with CBP. The interim regulation, which went into effect upon publication, made several changes to subpart C of part 133 of title 19 of the Code of Federal Regulations (19 CFR part 133) regarding the detention of suspect merchandise and the disclosure of information to mark owners during detention of goods bearing potentially counterfeit marks and after seizure of goods bearing counterfeit marks. These changes included a clarifying revision of the definition of ''counterfeit trademark'' and the addition of a 30-day detention period relative to goods suspected of bearing counterfeit marks.

CBP Dec. 12–10 sets forth a detailed discussion of the statutory scheme pertaining to enforcement of the intellectual property laws and CBP's derived authority to promulgate the interim amendments whereby CBP officers may disclose certain information that might comprise otherwise confidential commercial or financial information in order to assist CBP in identifying merchandise bearing counterfeit marks at the time of detention. *See* National Defense Authorization Act for Fiscal Year 2012 (NDAA) (Public Law 112–81, 10 U.S.C. 2302); Trade Secrets Act (18 U.S.C. 1905); Administrative Procedures Act (5 U.S.C. 551 *et seq.*); Lanham Act (15 U.S.C. 1124, 1125, 1127); Tariff Act of 1930, as amended (19 U.S.C. 1526(e) and 1595a(c)). Interested parties may refer to CBP Dec. 12–10 for that background information.

Although the interim regulatory amendments were promulgated without prior public notice and comment procedures and took effect on April 24, 2012, CBP Dec. 12–10 provided for the submission of public comments which would be considered before adoption of the interim regulations as a final rule.

Discussion of Comments

Twenty commenters responded to the interim rule's solicitation of public comment. Each submission consisted of multiple comments and several were submitted by or on behalf of associations. A majority of commenters expressed support for the interim rule's primary purpose of providing a procedure for the disclosure of information by CBP to mark owners for the purpose of determining whether imported goods bear counterfeit marks. Many of these commenters expressed the view that the interim rule does not go far enough to support CBP's enforcement efforts and made recommendations for improving the regulation.

A minority of commenters opposed the rule. Some of these commenters expressed concern that the interim regulation may have unintended consequences on the flow of legitimate trade, such as by enabling mark owners to prevent competing legitimate goods from entering commerce, and may create administrative burdens for the agency. The comments, and CBP's analyses thereof, are set forth below.

A. Terminology

For purposes of the comment discussion, the following terms are defined as set forth below:

- ''Section (b)(1) information'' refers to the specified information CBP is authorized to release under § 133.21(b)(1) of the interim regulation: Information appearing on suspect goods or their retail packaging (including labels) and unredacted samples or images (photographs, etc.) of the suspect goods or their retail packaging. ''Section (b)(1) information,'' in whatever form disclosed, may include manufacturer, shipper, exporter, or importer name and address when it appears on merchandise or its retail packaging, or serial numbers, dates of manufacture, lot codes, batch numbers, universal product codes, or other identifying marks, appearing on merchandise or its retail packaging in alphanumeric or other formats.
- The term ''unredacted sample'' refers to a sample (including its packaging) in its original condition as presented to CBP for examination.
- The term ''limited importation information'' refers to the basic information CBP releases under § 133.21(b)(2) of the interim regulation (redesignated as § 133.21(b)(4) in this final rule). Limited importation information consists of: Date of importation, port of entry, and description, quantity, and country of origin of the goods.
- The term ''redacted sample'' is used to describe samples of goods displaying information all of which or some of which has been removed, obscured, or obliterated. Such information may include the names and addresses of manufacturers, shippers, exporters, or importers that appear on merchandise or its retail packaging, or serial numbers, dates of manufacture, lot codes, batch numbers, universal product codes, or other identifying marks that appear on merchandise or its retail packaging in alphanumeric or other formats. Redacted samples may be photographed or otherwise reproduced for release to mark owners.
- ''Comprehensive importation information,'' released by CBP under § 133.21(d) of the interim regulation (redesignated as § 133.21(e) in this final rule), includes limited importation information plus the following additional information: Name and address of the manufacturer, exporter, and importer.
- The terms ''goods'' and ''merchandise'' are used interchangeably.

B. Comments Concerning Legal Issues

1. Comments Concerning Applicability of the Trade Secrets Act (18 U.S.C. 1905)

Comment: One commenter contended that the Trade Secrets Act only prohibits unauthorized disclosures of personally identifiable information by a government official or employee who received the information in the course of his employment.

CBP Response: CBP disagrees. The Trade Secrets Act applies to any information that ''. . . concerns or relates to the trade secrets, processes, operations, style of work, or apparatus, or to the identity, confidential statistical data, amount or source of any income, profits, losses, or expenditures of any person, firm, partnership, corporation, or association; . . . .'' (18 U.S.C. 1905).

Comment: Several commenters questioned CBP's interpretation of the Trade Secrets Act as set forth in the interim rule, which is that information appearing on imported articles and their retail packaging is information potentially covered by the Trade Secrets Act's protection against disclosure.

CBP Response: CBP's view is that while the Trade Secrets Act protects from disclosure information that identifies persons, or which may lead to the identification of persons, the Act is not limited to such information. The Act also covers a comprehensive array of business, commercial, and financial information.

Comment: Several commenters were of the view that CBP had changed its practice in 2008 to reflect that information appearing on imported articles and their retail packaging is information potentially covered by the Trade Secrets Act's protection against disclosure, and that subsequently CBP required that samples provided to mark owners be redacted.

CBP Response: The agency has consistently interpreted the Trade Secrets Act as prohibiting its employees from the unauthorized disclosure of protected information received in the course of their employment. From calendar year 2000 to publication of the interim rule on April 24, 2012, CBP's written policy was to provide, prior to seizure of goods bearing counterfeit marks, only limited importation information and/or redacted samples to mark owners (Customs Directive 2310–008A, April 7, 2000).

Comment: Several commenters stated that tracking information and other product coding are generally visible to the public and that any proprietary interest in this information belongs to the shipper and/or mark owner, not to the importer. These commenters contended that the Trade Secrets Act does not prohibit disclosure of this information to the mark owner.

CBP Response: As explained in the interim rule, markings, alphanumeric symbols, and other coding appearing on products or their retail packaging may reveal information regarding an importer's supply chain. This information is of the kind normally subject to Trade Secrets Act protection regardless of who may have applied the markings/symbols/coding to the products or packaging. The Trade Secrets Act permits those covered by the Act to disclose protected information when the disclosure is otherwise ''authorized by law,'' which includes properly promulgated substantive agency regulations authorizing disclosure based on a valid statutory interpretation. *See Chrysler* v. *Brown,* 441 U.S. 281, 294–316 (1979). Therefore, the ''authorized by law'' exception of the Trade Secrets Act allows CBP to disclose this protected information to the mark owner for the limited purpose of obtaining the mark owner's assistance in determining whether goods bear a counterfeit mark.

Comment: Some commenters stated that the interim regulation fails to safeguard the commercial and supply chain information that it purports to protect, as that information will inevitably become available to the public when the imported goods reach the market.

CBP Response: The Trade Secrets Act prohibits government officials from disclosing protected information received during the course of their employment or official duties, unless disclosure is exempted from the prohibition, regardless of whether the owner of that information may eventually disclose it to the public. Importers of merchandise detained under the provisions of the interim regulation may ultimately choose not to put the goods on the market or may otherwise dispose of the goods in a manner in which the aforementioned information appearing on the goods and/or packaging would never be disclosed to the public. Importers who choose to disclose such information are not subject to the Trade Secrets Act as they are not government employees who have received information pursuant to their employment. CBP's release of this information under the interim regulation's procedure is allowed under the ''authorized by law'' exception to the Trade Secrets Act, discussed above.

2. Comments Concerning the NDAA

Comment: One commenter stated that the NDAA is the sole authority for promulgating the interim regulation and requested that CBP clarify the legal basis for the regulation.

CBP Response: CBP disagrees with the commenter's premise. As explained in the interim rule, the NDAA is not the sole source of authority for the interim regulation's information disclosure procedure. In fact, several statutes, including 15 U.S.C. 1124, 1125, and 1127 and 19 U.S.C. 1526(e) authorize CBP to disclose to mark owners, for purposes of obtaining the mark owners' assistance in making infringement determinations, information that CBP may disclose under the interim regulation.

Comment: Several commenters contended that the NDAA only applies to products procured by the military and/or matters involving national defense concerns.

CBP Response: Several statutes authorize CBP to disclose to the mark owner the information set forth in the interim regulation, none of which, including the NDAA, is limited to military procurements and/or importations raising national defense concerns. The NDAA language is unambiguous and applies to any product CBP suspects of ''being imported in violation of section 42 of the Lanham Act.'' Therefore, CBP declines to limit the interim regulation's applicability as suggested by the commenters.

3. Comments Raising Other Legal Concerns

Comment: One commenter recommended that CBP amend the interim regulation to clarify that goods that are properly trademarked and that only use an additional protected trademark in a description of the product are not covered within the scope of this regulation.

CBP Response: In many cases, using a trademark in the way described by the commenter is permissible as a ''fair use'' of the trademark. ''Fair use'' is a well-established doctrine in trademark law that is recognized and honored by the courts. *See* section 33(b)(4) of the Lanham Act, 15 U.S.C. 1115(b)(4), which provides for a ''fair use'' defense when ''the use of the name, term, or device charged to be an infringement is a use, otherwise than as a mark, . . . or [use of] a term or device which is descriptive of and used fairly and in good faith only to describe the goods or services of such party.'' CBP honors the ''fair use'' doctrine, but does not believe it is necessary to include it in this CBP regulation.

Comment: Several commenters recommended that CBP amend the interim regulation to modify its definition of ''counterfeit'' based on their concerns that CBP officers could detain goods that are genuine, albeit repaired or refurbished goods, or goods bearing genuine marks that are unrestricted parallel imports.

CBP Response: The interim regulation employs the definition of ''counterfeit'' provided by the Lanham Act at 15 U.S.C. 1127.

Comment: Several commenters stated that the interim regulation should apply to other forms of intellectual property, such as suspected piratical or copyright infringing goods, and merchandise suspected of violating the Digital Millennium Copyright Act (DMCA), 17 U.S.C. 1201.

CBP Response: As the above comment concerns amendments to regulations concerning forms of intellectual property other than counterfeit marks, it falls outside the scope of this final rulemaking. CBP recognizes the concern that there be similar disclosure provisions relating to suspected piratical or copyright infringing goods and merchandise suspected of violating the Digital Millennium Copyright Act (DMCA), 17 U.S.C. 1201, and plans to address the issue through a separate proposed rulemaking.

C. Comments Concerning Action by Mark Owners

Comment: Several commenters noted that the interim regulation provides an opportunity for mark owners to potentially abuse the section (b)(1) information provided to them by CBP, and to disrupt or eliminate lawful parallel market competition. Several commenters recommended that CBP restrict mark owners' use of section (b)(1) information by placing conditions on the manner by which they may receive and use the information.

CBP Response: The interim regulation allows CBP to release section (b)(1) information to a mark owner after an importer has been notified and has had the opportunity to establish that the suspect goods bear genuine marks. This regulation is not intended to impede the legal importation of parallel (gray market) goods. However, to address the concern of these commenters, and the concern of those suggesting that conditions and limitations be placed on mark owners receiving section (b)(1) information, CBP is amending the interim regulation at 19 CFR 133.21(c) to include in the disclosure to the mark owner a statement that some or all of the information being disclosed may be information protected from disclosure by the Trade Secrets Act. The regulation provides that CBP is only disclosing the information to the owner of the mark for the purpose of assisting CBP in determining whether the merchandise bears a counterfeit mark. CBP will take into account, in deciding whether to make future disclosures to a mark owner, instances in which the mark owner has used the disclosed information for another purpose (*i.e.,* other than for assisting CPB in making the infringement determination).

Comment: Several commenters recommended that CBP amend the interim regulation to require mark owners receiving section (b)(1) information from CBP to provide certifications, under penalty of perjury, when reporting to CBP that goods are counterfeit and contain spurious versions of the specific marks recorded with CBP. One commenter contended that a certification would provide an assurance of veracity in a mark owner's response to CBP that the goods bear counterfeit marks.

CBP Response: A certification step would add administrative complexity and impede CBP's ability to determine a suspect good's admissibility as quickly as possible. The responsibility for determining whether the goods bear counterfeit marks rests with CBP which routinely determines the admissibility of goods under numerous provisions of customs and other laws. In doing so, CBP considers and determines the veracity of information and the authenticity of documents presented by importers, mark owners, and others who participate in various procedures administered under the customs laws and regulations. CBP will not seize merchandise based solely on information provided by the mark owner when CBP deems such information to be insufficient or inconsistent with the facts of the case.

Comment: One commenter expressed concern that mark owners will delay and/or fail to be responsive to CBP's inquiries regarding authenticity of marks appearing on suspect goods, thereby prejudicing the right of importers to an orderly and reasonably expeditious process.

CBP Response: CBP believes the commenter's concern will be the exception, not the rule. The interim regulation's detention period extends for 30 days from the date goods are presented for examination, which CBP deems a reasonable time frame considering the potential urgency of the matter. Most cases will be resolved within the 30-day period. If detained articles are not released within the detention period, the articles are deemed excluded in accordance with 19 U.S.C. 1499(c)(5) for purposes of 19 U.S.C. 1514(a)(4), which pertains to an importer's right to protest CBP's decisions. Therefore, delay by the mark owner, whatever the reason, will not deprive the importer of recourse to gain release of its merchandise where the facts warrant such release.

D. Comments Pertaining to the Interim Regulation's Procedure

1. Comments Concerning the Procedure Generally

Comment: Some commenters noted that there could be a potential disruption to the flow of legitimate trade by the interim regulation's required procedures.

CBP Response: CBP acknowledges that some goods initially suspected of bearing counterfeit marks will ultimately be determined to be genuine or otherwise non-violative and that the release of these genuine goods will be delayed to some extent. However, the interim regulation's procedure is structured to resolve these issues in a reasonably expedited manner, while giving appropriate notices to impacted parties. Suspect goods found to be genuine will be released expeditiously.

Comment: One commenter, an importer, stated that the interim regulation's procedure prevents CBP from seeking assistance in determining whether the suspect goods bear counterfeit marks until CBP issues a notice of detention to the importer. The commenter contended that this procedure impedes CBP's enforcement effort.

CBP Response: CBP disagrees with the commenter's characterization of the process. In order to seek assistance from a mark owner CBP may, at its discretion at any time after merchandise is presented for examination, disclose limited importation information and redacted samples (or photographs/images) to a mark owner.

Comment: The same commenter stated that the interim regulation's procedure prevents CBP from seeking assistance from the mark owner within the seven business day period after issuance of the detention notice.

CBP Response: Again, CBP disagrees with the commenter's characterization of the process. As stated above, CBP may, at its discretion at any time after merchandise is presented for examination, disclose limited importation information and redacted samples (or photographs/images) to a mark owner.

Comment: One commenter recommended that CBP amend the regulation to require that a mark owner post a bond in order to receive a sample only when the value of the sample released to the mark owner is $500 or more.

CBP Response: CBP believes that the bonding requirements set forth in this final rule are appropriate to indemnify the importer against any loss or damage resulting from the furnishing of a sample to the mark owner for purposes of assisting the government in making an infringement determination.

Comment: Several commenters recommended that CBP provide in the regulation an opportunity for the importer to have a sample of the suspect goods tested by a qualified laboratory rather than providing a sample to the mark owner.

CBP Response: CBP recognizes that laboratory analysis may, in certain instances, be a valuable tool in determining whether goods bear genuine marks. CBP will consider any information, including laboratory reports, provided by an importer to support the admissibility of goods detained under the interim regulation. While information from a laboratory may lead CBP to decide it is not necessary to provide a sample to a mark owner, that is not necessarily the case.

Comment: One commenter, an association representing mark owners, stated that its members strongly oppose giving importers the principal role in authenticating detained products and requests that CBP provide right holders with unredacted samples and a direct voice in determining authenticity.

CBP Response: This final rule does not give importers the principal role in authenticating suspected counterfeit marks. Pursuant to 19 U.S.C. 1499, CBP has the ultimate responsibility for determining whether a suspected mark is counterfeit. Moreover, this final rule provides the right holders with unredacted samples and photographs and an opportunity to provide CBP with input regarding whether the goods bear a counterfeit mark whenever CBP has an unresolved suspicion.

Comment: Some commenters stated that allowing the importer an opportunity to establish that its imported goods are genuine invites fraud and questioned whether CBP would be able to determine the authenticity of documents and information provided by an importer.

CBP Response: There is always a risk that CBP receives incorrect information, whether from an importer or another interested party. CBP, however, has extensive experience in determining the admissibility of goods under the numerous provisions of the customs laws and other laws it enforces and is well aware of the potential for fraud. CBP has developed expertise in determining the admissibility of goods presented for entry and routinely considers the veracity and authenticity of information and documents that importers (and others) present to CBP.

Comment: One commenter recommended that CBP include a mechanism under the interim regulation's procedure by which mark owners may object to a determination by CBP that a suspected counterfeit mark is not counterfeit, after the mark owner receives either limited importation information or section (b)(1) information from CBP.

CBP Response: As stated in CBP Dec. 12–10 and noted above, the objective of this rulemaking is to facilitate CBP's solicitation of information from both mark owners and importers to better enable CBP to determine a good's admissibility while safeguarding, to the greatest extent possible, information that is protected by the Trade Secrets Act. The mark owner receives more than limited importation information in that the right holder is provided with an unredacted sample or digital images containing information appearing on the suspect article. The disclosure of this information allows the right holder to provide CBP with the information necessary for making a determination relative to the suspect mark and for determining whether the article bears a counterfeit mark.

Comment: One commenter noted with disapproval that the interim regulation provides for a 30-day window from the date of importation for CBP to make a determination of ''reasonable suspicion'' and requires CBP to issue a notice of detention to the importer within five business days of that determination.

CBP Response: CBP disagrees with the commenter's reading of the regulation. Under 19 U.S.C. 1499, CBP must decide whether to release or detain merchandise within five business days following the date on which merchandise is presented for examination. Therefore, a five business day window exists within which CBP must make a reasonable suspicion determination, not a 30-day window. CBP is also required to issue a notice of detention to the importer no later than five business days after a decision to detain the merchandise is made. Therefore, the importer will learn of the detention within ten business days of the merchandise being presented for examination.

Comment: Several commenters stated that CBP should be required to issue uniform notices of detention that specify the reason(s) for detention.

CBP Response: CBP agrees as this requirement is mandated by 19 U.S.C. 1499(c)(2)(B).

Comment: One commenter, citing language from the interim rule's preamble, recommended that CBP amend the interim regulation to explicitly state that goods will be detained only when CBP ''reasonably suspects'' that they bear counterfeit marks.

CBP Response: CBP believes that it is unnecessary to codify in the regulations factors, elements, and/or circumstances it must consider, on a case-by-case basis, in determining whether goods are subject to detention for a determination of violation of the intellectual property laws.

Comment: A commenter recommended that CBP define the ''good cause'' an importer must show under the interim regulation to justify an importer's request for a 30-day extension of the detention period.

CBP Response: CBP no longer believes that such a 30-day extension is warranted and has eliminated it in this final rule. In the past, extensions were granted to provide time to determine admissibility. CBP is confident that with the assistance and input of the right holder, admissibility determinations can be made within the 30-day period.

Comment: One commenter stated that the interim regulation simply codifies in the regulations what, prior to the promulgation of the interim rule, had been the regulatory *status quo* inasmuch as mark owners may obtain unredacted samples only after CBP determines that the subject goods bear counterfeit marks and seizes them or formulates the intention to seize them.

CBP Response: CBP disagrees with the commenter's reading of the interim regulation. CBP may, when necessary to determine whether suspect goods bear counterfeit marks, disclose unredacted samples to the owner of the mark in accordance with the interim regulation's notice (to the importer) provisions. This disclosure takes place after detention but before either seizure or the formulation of an intent to seize.

Comment: One commenter objected to the interim regulation as not providing protection to importers against disclosure to mark owners of information protected by the Trade Secrets Act with respect to marks that are not recorded with CBP.

CBP Response: The interim regulation does, in fact, require that a mark be registered with the U.S. Patent and Trademark Office and recorded with CBP as a prerequisite to the agency detaining goods it suspects bear a counterfeit version of the mark and disclosing information (or samples or photographs/images) to the mark owner under § 133.21(b) of the interim regulation. CBP believes that this long-standing requirement is warranted and will continue to impose it. Without it, CBP would lack information needed to enforce the prohibition against counterfeit marks, and the process would become more complex and significantly less workable.

Comment: Several commenters stated that the interim regulation does not provide an objective standard for establishing the genuine nature of marks appearing on imported goods. These commenters recommended that CBP amend the interim regulation to include examples of the kind of information it will accept as tending to prove that marks are genuine.

CBP Response: CBP believes that it is unnecessary to amend the regulation, as CBP will consider any document or information that is relevant to the question of the authenticity of the mark. Inevitably, some documents or information submitted to CBP by an importer or a mark owner will be less persuasive or probative. These decisions are case-specific and depend on the circumstances involved. In this context, CBP finds little benefit to limiting the kinds of information it will consider.

2. Comments Concerning the Release of Information

Comment: One commenter recommended that prior to CBP's disclosure of section (b)(1) information to the mark owner, the agency should provide the information to the importer for its consideration of the accuracy and veracity of that information. Several commenters recommended that CBP allow importers to obtain samples of suspect goods to assist them in responding to CBP's request for information regarding the goods. Some of these latter commenters also recommended that importers be permitted to receive samples of seized goods to enable them to respond to seizure and/or penalty notices.

CBP Response: Inasmuch as an importer may not have complete information about the marks appearing on imported goods and/or their retail packaging, CBP finds merit in releasing this information to importers and is amending the interim regulation (*see* new § 133.21(d)) to provide release of an unredacted sample/packaging/image to the importer any time after presentation of the goods for examination. CBP believes that releasing this information to importers will assist them in providing CBP with a meaningful response before or within the seven business day response period. Under this amended provision, if an importer does not identify a need for a sample until after CBP seizes goods as bearing counterfeit marks the importer may request a sample at that time.

Comment: Several commenters recommended that the interim regulation's procedure for issuing a notice of detention to the importer be expanded to provide, simultaneously rather than within 30 business days of detention, the notice of the detention and limited importation information to the mark owner. This would eliminate unnecessary delay.

CBP Response: CBP finds merit in this recommendation and is amending § 133.21(b) of the interim regulation accordingly. The amended provision will no longer provide that CBP has 30 business days from the date of detention to release limited importation information to the mark owner; if available, such information will be released upon issuance of the detention notice to the importer (or as soon as possible thereafter if not immediately available). This simultaneous notice and release of limited importation information provision will apply in those instances where CBP has not already released limited importation information to the mark owner in accordance with its discretionary release authority under the same section of the interim regulation.

Comment: Several commenters recommended that CBP amend the interim regulation to allow disclosure to another person in place of the mark owner, where there is an arrangement between the other person and the mark owner, such as an assignment, a license, or other agreement. Such other persons may be in a better position to assist CBP in identifying goods bearing counterfeit marks.

CBP Response: CBP discloses such information to the person designated by the mark owner during the recordation process as the contact for enforcement of the mark (*see* §§ 133.1 through 133.7 of this part). However, due to the administrative difficulty in determining which additional persons may be entitled to receive such information, CBP is not amending the regulations in this regard.

Comment: Several commenters recommended that CBP limit the circumstances in which unredacted samples are released to mark owners by first releasing a redacted sample to the mark owner. An unredacted sample can then be released when the redacted sample proves insufficient for the mark owner to assist CBP in determining whether the goods bear a counterfeit mark.

CBP Response: CBP believes that the interim regulation adequately safeguards importers' interests and that it would be counter-productive and unduly burdensome administratively to impose additional procedural steps before releasing an unredacted sample to the mark owner. The result would be more instances where resolution of the matter would require all or nearly all of the 30-day detention period, which is contrary to CBP's goal to quickly resolve issues of admissibility so as to either enable lawful trade or to prevent violative goods from entering the commerce of the United States.

Comment: Several commenters recommended that CBP make the interim regulation's disclosure provision mandatory rather than permissive, requiring CBP, in every case, to disclose section (b)(1) information, including unredacted samples.

CBP Response: The interim regulation permits CBP to disclose to mark owners, prior to seizure, section (b)(1) information (including an unredacted sample) when CBP finds that obtaining a mark owner's assistance regarding the authenticity of a mark is warranted, subject to the notice and seven business day response period set forth in § 133.21(b)(2)(i). *See* § 133.21(c). CBP will weigh the facts and circumstances before releasing section (b)(1) information (prior to seizure). CBP therefore does not agree with the commenters' recommendation to require the pre-seizure release of section (b)(1) information to the mark owner in every case. CBP believes that the interim regulation's procedure protects importers' interests in the confidentiality of their commercial and supply chain information while, at the same time, facilitating CBP's trademark enforcement at the border.

Comment: One commenter recommended that CBP clarify that release of information is only authorized after detention, rather than at any time after importation.

CBP Response: Although this comment is accurate regarding release of section (b)(1) information to the mark owner under the interim regulation, this final rule amends § 133.21(b)(4), as explained above, to reflect that CBP may release limited importation information to the mark owner prior to issuance of a notice of detention to the importer and will release such information to the mark owner upon issuance of the notice of detention or as soon as possible after its issuance. This latter change removes the 30-business day window specified in the interim regulation and mandates that CBP will release this information, when available, contemporaneously with issuance of the detention notice to the importer.

Comment: Some commenters recommended that the interim regulation be amended to permit CBP to disclose unredacted samples to the owner of the mark at any time after goods are presented for entry, without the seven business day response period. Some commenters recommended that this response period be eliminated, observing that applicable law does not require a role for the importer in the authentication process.

CBP Response: CBP believes that the regulation strikes the appropriate balance between protecting importers' commercial information and allowing mark owners to assist CBP in enforcing prohibitions against counterfeit goods. Section 1499(a)(5) within 19 U.S.C. specifies the manner in which an importer may provide information to CBP when information is required for the release of goods. Accordingly, importers have a statutorily prescribed role in establishing the admissibility of their goods. At any time after goods are presented for examination, CBP may solicit and receive information from the importer that may enable CBP to expeditiously release the goods. In cases where information is not provided within five days or the information received is insufficient to enable CBP to release the goods, pursuant to 19 U.S.C. 1499, CBP may detain the goods to enable CBP to determine their admissibility. Should CBP require assistance from a mark owner to determine admissibility of the goods, it may seek assistance at various stages of the detention and may disclose section (b)(1) information, if necessary, after the seven business day response period. Under 19 U.S.C. 1499, if CBP does not make a final determination regarding the admissibility of the goods within 30 days of presentation of the merchandise for examination, its failure to make such a determination is treated as a decision to exclude the merchandise for purposes of 19 U.S.C. 1514(a)(4). CBP believes that the above process allows the mark owner adequate time to provide information to CBP when CBP requests such information while protecting importers' commercial information.

Comment: One commenter suggested that CBP amend the interim regulation to require the importer to provide to the mark owner any information it submits to CBP within the seven business day response period. Another commenter suggested that CBP provide to the mark owner a non-proprietary version of the information the importer provided to CBP.

CBP Response: It is CBP's role to determine whether, in light of the relevant laws and regulations, goods that are presented for examination are admissible. The interim regulation simply facilitates CBP's solicitation of information from both mark owners and importers to better enable CBP to determine a good's admissibility while safeguarding as much as possible information that is protected by the Trade Secrets Act.

3. Other Comments Concerning the Seven Business Day Response Period

Comment: Several commenters recommended that CBP exempt certain industries from the interim regulation's seven business day response period, contending that some industries have special needs requiring information sharing with the mark owner, without delay, in every case.

CBP Response: CBP believes that the interim regulation's procedure will operate effectively across all industries and sectors. Should CBP recognize a need to address a specific industry's circumstances in the future, CBP will consider amending the regulation at that time.

Comment: One commenter expressed concern that the interim regulation's seven business day response period will impair a mark owner's ability to assist CBP in its efforts to curtail importation of restricted parallel imports or to assist CBP in identifying counterfeit goods that are commingled with unrestricted gray market goods.

CBP Response: The interim regulation did not change the way CBP enforces restrictions on gray market goods. The seven business day response period neither impairs the mark owner's ability to make information available to CBP nor increases the risk of counterfeit goods being admitted. Unless CBP determined the goods are admissible, they are deemed excluded by operation of law. CBP is aware of the potential for these types of shipments and has developed expertise in identifying such activity.

Comment: Some commenters stated that the interim regulation's seven business day response period makes the process for authenticating marks unduly burdensome and that officers charged with enforcing the intellectual property laws may therefore be deterred from taking action.

CBP Response: CBP believes that the interim regulation's procedure will assist CBP officers in making determinations regarding counterfeit marks and is similar to various other provisions in the CBP regulations that require CBP to issue notice to an importer or other party of actions it is undertaking and/or receive information from an importer or other party before taking action. CBP is also confident that its officers will discharge their sworn duties efficiently, responsibly, and professionally at all times.

Comment: Some commenters stated that the interim regulation's seven business day response period will result in the delayed release of legitimate goods. Several other commenters specified that the seven business day response period is too long and may result in the mark owner receiving information to determine authenticity of the mark(s) with as little as 11 days left in the 30-day detention period. These commenters contended that this is not enough time for mark owners to provide meaningful information and is prejudicial to mark owners' interests.

CBP Response: CBP believes that, in the interest of due process, the seven business day response period is appropriate and that the regulation provides adequate time for both importers and mark owners to respond and does not prejudice their interests. CBP further notes that if CBP fails to make a determination within the 30-day detention period the merchandise is excluded by operation of law.

Comment: Several commenters stated that the interim regulation's seven business day response period is too short, inasmuch as it may not provide enough time for an importer to provide information sufficient to establish to CBP's satisfaction that detained goods bear genuine marks.

CBP Response: CBP disagrees. Although CBP may release section (b)(1) information to the mark owner after the seven business day response period, the importer has the option of submitting information to CBP up to the end of the detention period or until CBP determines that the goods bear counterfeit marks. CBP believes that this time frame is adequate to protect importers' interests.

E. Comments Concerning Information Released

Comment: Several commenters objected to the disclosure of information provided in § 133.21(b)(2) of the interim regulation whereby CBP may disclose to the mark owner, prior to CBP's seizure of the goods as bearing counterfeit marks, the quantity and description of merchandise involved in a suspect shipment.

CBP Response: CBP can disclose the quantity and description of merchandise at any time after merchandise is presented for examination as CBP does not consider this information to be protected by the Trade Secrets Act. CBP articulated this position in T.D. 98–21, published in the **Federal Register** (63 FR 11996) on March 12, 1998. Nothing in the comments has persuaded CBP to change its view.

Comment: Several commenters contended that the interim regulation is unclear as to the meaning of ''quantity'' and the manner by which CBP will provide the mark owner with a description of merchandise ''from the entry.''

CBP Response: CBP agrees that these provisions require more clarity. Accordingly, CBP is amending the regulation to provide that the quantity of merchandise involved in the detention and the description of detained merchandise will be drawn from CBP arrival or entry documents or their electronic equivalents, which could include, but will not be limited to, the CBP Form 3461, the CBP Form 7533, the CBP Form 7512 (if the detention is for merchandise moving in-bond), the cargo manifest (if no entry has yet been filed), or any other document or information, as applicable.

Comment: One commenter requested that CBP reconsider the scope of information that it redacts when providing samples or photographs/

images to a mark owner under § 133.21(b)(3) of the interim regulation. The commenter observed that determining whether suspect goods bear counterfeit marks may require a mark owner to review information such as product codes, packaging, and SKUs and that disclosing these marks and numbers does not violate the Trade Secrets Act as they may not necessarily identify the importer.

CBP Response: CBP believes that in order to protect importers' interests, any identifying information such as serial numbers, dates of manufacture, lot codes, batch numbers, universal product codes, the name or address of the manufacturer, exporter, or importer of the merchandise, or any mark that could reveal the name or address of the manufacturer, exporter, or importer of the merchandise, in alphanumeric or other formats, should be redacted when CBP provides samples, photographs, or images prior to the running of the seven business day response period.

Comment: One commenter stated that the interim regulation is deficient in that it provides for disclosure of only certain limited information appearing on the packaging of suspect merchandise. The commenter contended that the mark owner may need more information to provide meaningful assistance.

CBP Response: CBP disagrees with the commenter's reading of the interim regulation. CBP is not limited to disclosing information appearing only on the packaging of suspect merchandise. Once the seven business day response period has expired without resolution of authenticity, CBP is authorized to disclose to the mark owner all information appearing on the goods as well as all information appearing on their retail packaging. The NDAA specifically authorizes CBP to disclose certain information to a mark owner, including unredacted samples and photographs/images of suspect merchandise (and its retail packaging). The interim rule is consistent with that grant of authority.

F. Comments Concerning Post-Seizure

Comment: Several commenters recommend that CBP make the interim rule's post-seizure disclosure provision mandatory rather than discretionary, requiring CBP, in every case, to provide unredacted photographs/images or samples of the goods seized to the mark owner.

CBP Response: CBP does not believe that post-seizure disclosure to mark owners needs to be made mandatory through regulations.

Comment: One commenter recommended that CBP amend the interim regulation to require the retention of seized counterfeit goods for at least 60 days after CBP has provided the mark owner with formal notice of the seizure. The commenter stated that CBP often disposes of the goods before notice is given, depriving mark owners of the opportunity to request and obtain samples.

CBP Response: The comment inaccurately reflects CBP's procedure regarding seizure, forfeiture, and destruction of goods bearing counterfeit marks. Generally, CBP retains seized merchandise for at least 90 days from the date of seizure, through completion of the forfeiture process, prior to destruction of the goods. Section 133.21(d) of the interim regulation (redesignated in this final rule as § 133.21(e)) requires CBP to disclose to the mark owner comprehensive importation information, if available, within 30 business days of the notice of seizure to the importer.

Comment: Several commenters recommended that CBP commit to rendering determinations on 19 U.S.C. 1618 petitions (challenging the seizure or forfeiture or both) no later than 30 days after such petitions are filed.

CBP Response: Part 171 of the CBP regulations governs the agency's handling of petitions for remission or mitigation of fines, penalties, and forfeitures filed pursuant to 19 U.S.C. 1618. CBP believes that the administrative procedure set forth in its existing regulations is adequate to protect importers' interests in matters involving seized merchandise and that an amendment to these regulations is unnecessary.

Conclusion and List of Changes

Based on the foregoing analysis of the comments and CBP's further consideration of the matter, CBP is adopting the interim amendments to the CBP regulations published in the **Federal Register** (77 FR 24375) on April 24, 2012 as final with the exception of the amendments to §§ 133.21 and 151.16 which are being adopted as final with the following modifications:

CBP is amending § 133.21 to enhance its readability and to reflect the clarifications, amendments and organizational changes discussed above. Specifically:

1. CBP is amending § 133.21(b) by eliminating the optional 30-day extension of the detention period as CBP now believes that such an extension is unnecessary.

2. CBP is reorganizing the text of § 133.21(b) by redesignating the existing introductory text and paragraphs (b)(1), (b)(2), and (b)(3) as newly redesignated paragraphs (b)(1) through (b)(5). Within § 133.21(b):

• Paragraph (b)(1) restates the 30-day detention period provided for in 1499(c).

• Paragraph (b)(2)(i) specifies that a notice of detention is issued to the importer pursuant to 19 CFR 151.16(c) and 19 U.S.C. 1499(c), and that CBP will also inform the importer that certain information may already have been disclosed to the owner of the mark, or may be disclosed concurrent with the issuance of the notice of detention, and that the importer has seven business days from the date of the notice of detention to present information that establishes, to CBP's satisfaction, that the detained merchandise does not bear a counterfeit mark.

• New paragraph (b)(2)(ii) provides that where the importer does not provide information within the seven business day response period, or the information provided is insufficient for CBP to determine that the merchandise does not bear a counterfeit mark, CBP may proceed with the disclosure to the owner of the mark and will so notify the importer.

• Paragraph (b)(3) sets forth the information CBP may disclose to the mark owner (information appearing on goods and their retail packaging and unredacted samples, photographs/images, etc.).

• Redesignated paragraph (b)(4) (paragraph (b)(2) of the interim regulation) is amended to clarify that the ''description of the merchandise'' and the ''quantity involved'' that CBP releases to the mark owner (along with other data) prior to issuance of a detention notice is taken from the paper or electronic equivalent of CBP Forms 3461, 7533, 7512, cargo manifest, advance electronic information, or other entry document as appropriate. After issuance of a detention notice, this information is taken from the notice of detention. CBP will release the information at the same time it issues the detention notice to the importer, or as soon afterward as possible.

• Paragraph (b)(5) provides for release of redacted photographs/images and samples to the mark owner.

3. In § 133.21(c), pertaining to release of unredacted *photographs, images and* samples to the mark owner under paragraph (b), CBP is:

• Clarifying the heading text to state that the provision pertains to conditions associated with the disclosure.

• Adding language to provide that, with the release of the information or the photographs, images or samples, CBP will notify the mark owner that some or all of the information it is receiving may be subject to the protections of the Trade Secrets Act, and is only being provided to the mark owner to assist CBP in determining whether the merchandise described in the notice of detention bears counterfeit marks.

• Reorganizing the provision into two sub-paragraphs to enhance readability.

4. Sections 133.21(b)(5), (c)(2),and (f), relating to the terms of the IPR sample bond, are amended to clarify that the IPR sample bond is posted to indemnify the importer or owner of the sample against any loss or damage resulting from the furnishing of the sample by CBP to the owner of the mark.

5. CBP is adding a new paragraph (d) to § 133.21 to provide for release of unredacted samples to the importer any time after presentation of the suspect goods to CBP for examination.

6. Existing § 133.21(d), pertaining to the seizure of goods and disclosure of comprehensive importation information to the mark owner, is re-designated as paragraph (e) in this final rule and clarified to reflect that the ''description'' and the ''quantity'' of the merchandise provided to the mark owner by CBP is taken from the notice of seizure (and intent to forfeit).

7. Existing § 133.21(e), pertaining to photographs/images and samples being made available to the mark owner after seizure, is re-designated as paragraph (f) in this final rule.

8. Existing § 133.21(f), pertaining to consent of the mark owner, is re-designated as paragraph (g) in this final rule.

This document amends the specific authority citation for §§ 133.21 through 133.25 to reflect 10 U.S.C. 2302.

Lastly, this final rule amends § 151.16(a) by removing the reference to ''imports of articles bearing counterfeit marks or suspected counterfeit marks.''

CBP is adopting as final, with the clarifications and amendments discussed above, the interim amendments set forth in CBP Dec. 12–10 that went into effect on April 24, 2012. The additional changes made to the interim regulation in this final rule include non-substantive editorial changes that improve readability, as well as logical-outgrowth changes to the interim regulation's provisions, as described above. In an effort to provide the trade, if necessary, with the opportunity to make adjustments to their business practices, CBP has determined to delay the effective date of this final rule for a period of 30 days from the date of publication of this document in the **Federal Register**.

Executive Orders 13563 and 12866

Executive Orders 13563 and 12866 direct agencies to assess 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. This rule has been designated a ''significant regulatory action'' although not economically significant, under section 3(f) of Executive Order 12866. Accordingly, the rule has been reviewed by the Office of Management and Budget.

Regulatory Flexibility Act

The Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*), as amended by the Small Business Regulatory Enforcement and Fairness Act of 1996, requires agencies to assess the impact of regulations on small entities. A small entity may be a small business (defined as any independently owned and operated business not dominant in its field that qualifies as a small business per the Small Business Act); a small not-for-profit organization; or a small governmental jurisdiction (locality with fewer than 50,000 people).

One of CBP's primary roles is to safeguard the U.S. economy from the importation of counterfeit goods. Prior to the publication of the interim final rule, if CBP needed assistance in determining whether an import bears counterfeit marks, the agency was restricted to only sharing redacted samples of the import in question with a right holder. However, due to the highly technical nature of some imports and the continuously increasing sophistication of counterfeiters, sharing redacted samples with right holders is no longer sufficient in certain circumstances. To broaden CBP's ability to identify counterfeit goods, Congress included a provision to the National Defense Authorization Act for Fiscal Year 2012 (NDAA) (Public Law 112–81, 10 U.S.C. 2303) that allows CBP to share unredacted samples of imports suspected of bearing counterfeit marks with the right holders of the trademarks in question in order to aid CBP in determining whether the suspect goods are violative.[1]

By sharing unredacted samples of imports with mark owners, however, mark owners may gain access to some sensitive information about the importer, such as its supply chain and purchase price. To mitigate the potential unnecessary release of an importer's trade secrets to a mark owner, the interim final rule established a procedure to allow an importer seven business days to demonstrate to CBP that suspect marks are not violative. If the importer is unable to do so, CBP may seek assistance from the mark owner by releasing unredacted samples of the import(s) in question. As discussed earlier, during the comment period for the interim final rule CBP received comments regarding the possible misuse of trade secret information by mark owners when viewing unredacted samples. In order to address such misuses, and thus any potential business impacts to the importation of legitimate trade, CBP is amending the interim regulation to provide that the disclosure to the mark owner must include a statement informing the mark owner that some or all of the information being disclosed may be information protected from disclosure by the Trade Secrets Act (18 U.S.C. 1905).

As described in the ''Paperwork Reduction Act'' section of this document, CBP estimates that it takes an importer two hours to provide proof to CBP that establishes that suspect goods do not bear counterfeit marks. CBP estimates the average wage of an importer to be $28.50 per hour. Thus, CBP estimates it will cost a small entity $57.00 to demonstrate that its import does not bear counterfeit marks. CBP does not believe $57.00 constitutes a significant economic impact. CBP does recognize, however, that such repeated inquiries could eventually rise to the level of a significant economic impact. CBP lacks data on how often a particular importer would be affected by this regulation. CBP subject matter experts, however, are unaware of any instances where a particular importer was repeatedly requested to provide information to CBP for the purpose of establishing that an import does not bear counterfeit marks. Additionally, based on CBP's experience over the years (including in implementing the interim rule), CBP anticipates that law-abiding importers will not be subject to the provisions in this rule on a repeated basis. Further, we note that providing this information to CBP is optional on the part of the importer. CBP did not

[1] Note that this rule does not alter CBP's ability to provide redacted photographs/images, samples, or retail packaging (including labels) of suspect merchandise to the right holder of the trademark without prior notification to the importer.

receive any comments on the interim final rule regarding the cost to importers of providing proof to CBP that establishes that suspect goods do not bear counterfeit marks. Due to the harm that counterfeit goods pose to public health and safety, this rule went into effect as an interim final rule on the date of its publication on April 24, 2012. As discussed earlier, CBP lacks data on how many importers have been affected by the interim rule, and on how often any particular importer has been affected. As a general matter, any importer may be affected by this rule, and that is because the rule will be applied when CBP cannot make a determination—without the use of these regulatory provisions—as to whether an import(s) bears a counterfeit mark. Because this rule could be applied to any importer, CBP believes that this rule will potentially have an effect on a substantial number of small entities.

While this rule will potentially have an effect on a substantial number of small entities, CBP does not believe that an estimated cost to an importer of $57.00 per affected import constitutes a significant economic impact (also, as discussed above, providing this information to CBP is optional on the part of the importer). Thus, CBP certifies this regulation will not have a significant economic impact on a substantial number of small entities.

Paperwork Reduction Act

In accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507), the collections of information for this document are included in an existing collection for Notices of Detention (OMB control number 1651–0073). An agency may not conduct, and a person is not required to respond to, a collection of information unless the collection of information displays a valid control number assigned by OMB.

The burden hours related to the Notice of Detention for OMB control number 1651–0073 are as follows:

Number of Respondents: 1,350.

Number of Responses: 1,350.

Time per Response: 2 hours.

Total Annual Burden Hours: 2,700.

There is no change in burden hours under this collection with this rule.

Signing Authority

This rulemaking is being issued in accordance with 19 CFR 0.1(a)(1), pertaining to the authority of the Secretary of the Treasury (or that of his or her delegate) to approve regulations concerning trademark enforcement.

List of Subjects

19 CFR Part 133

Copying or simulating trademarks, Copyrights, Counterfeit trademarks, Customs duties and inspection, Detentions, Reporting and recordkeeping requirements, Restricted merchandise, Seizures and forfeitures, Trademarks, Trade names.

19 CFR Part 151

Customs duties and inspection, Examination, Imports, Penalties, Reporting and recordkeeping requirements, Sampling and testing.

Amendments to the CBP Regulations

Accordingly, the interim rule amending parts 133 and 151 of title 19 of the Code of Federal Regulations (19 CFR parts 133 and 151), which was published at 77 FR 24375 on April 24, 2012, is adopted as final with the following changes:

PART 133—TRADEMARKS, TRADE NAMES, AND COPYRIGHTS

■ 1. The general authority citation for part 133 continues, and the specific authority citation for §§ 133.21 through 133.25 is added, to read as follows:

Authority: 15 U.S.C. 1124, 1125, 1127; 17 U.S.C. 101, 601, 602, 603; 19 U.S.C. 66, 1202, 1499, 1526, 1624; 31 U.S.C. 9701. Sections 133.21 through 133.25 also issued under 18 U.S.C. 1905; Sec. 818(g), Pub. L. 112–81 (10 U.S.C. 2302);

■ 2. In § 133.21:

■ a. Paragraphs (b) and (c) are revised;

■ b. Paragraphs (d), (e), and (f) are redesignated as paragraphs (e), (f), and (g);

■ c. A new paragraph (d) is added; and

■ d. Redesignated paragraphs (e) and (f) are revised.

The revisions and addition read as follows:

§ 133.21 Articles suspected of bearing counterfeit marks.

* * * * *

(b) *Detention, notice, and disclosure of information*—(1) *Detention period.* CBP may detain any article of domestic or foreign manufacture imported into the United States that bears a mark suspected by CBP of being a counterfeit version of a mark that is registered with the U.S. Patent and Trademark Office and is recorded with CBP pursuant to subpart A of this part. The detention will be for a period of up to 30 days from the date on which the merchandise is presented for examination. In accordance with 19 U.S.C. 1499(c), if, after the detention period, the article is not released, the article will be deemed excluded for the purposes of 19 U.S.C. 1514(a)(4).

(2) *Notice of detention to importer and disclosure to owner of the mark*—(i) *Notice and seven business day response period.* Within five business days from the date of a decision to detain suspect merchandise, CBP will notify the importer in writing of the detention as set forth in § 151.16(c) of this chapter and 19 U.S.C. 1499. CBP will also inform the importer that for purposes of assisting CBP in determining whether the detained merchandise bears counterfeit marks:

(A) CBP may have previously disclosed to the owner of the mark, prior to issuance of the notice of detention, limited importation information concerning the detained merchandise, as described in paragraph (b)(4) of this section, and, in any event, such information will be released to the owner of the mark, if available, no later than the date of issuance of the notice of detention; and

(B) CBP may disclose to the owner of the mark information that appears on the detained merchandise and/or its retail packaging, including unredacted photographs, images, or samples, as described in paragraph (b)(3) of this section, unless the importer presents information within seven business days of the notification establishing that the detained merchandise does not bear a counterfeit mark.

(ii) *Failure of importer to respond or insufficient response to notice.* Where the importer does not provide information within the seven business day response period, or the information provided is insufficient for CBP to determine that the merchandise does not bear a counterfeit mark, CBP may proceed with the disclosure of information described in paragraph (b)(3) of this section to the owner of the mark and will so notify the importer.

(3) *Disclosure to owner of the mark of information appearing on detained merchandise and/or its retail packaging, including unredacted photographs, images or samples.* When making a disclosure to the owner of the mark under paragraph (b)(2)(ii) of this section, CBP may disclose information appearing on the merchandise and/or its retail packaging (including labels), images (including photographs) of the merchandise and/or its retail packaging in its condition as presented for examination (*i.e.,* an unredacted condition), or a sample of the merchandise and/or its retail packaging in its condition as presented for examination. The release of a sample will be in accordance with, and subject to, the bond and return requirements of

paragraph (c) of this section. The disclosure may include any serial numbers, dates of manufacture, lot codes, batch numbers, universal product codes, or other identifying marks appearing on the merchandise or its retail packaging (including labels), in alphanumeric or other formats.

(4) *Disclosure to owner of the mark of limited importation information.* From the time merchandise is presented for examination, CBP may disclose to the owner of the mark limited importation information in order to obtain assistance in determining whether an imported article bears a counterfeit mark. Where CBP does not disclose this information to the owner of the mark prior to issuance of the notice of detention, it will do so concurrently with the issuance of the notice of detention, unless the information is unavailable, in which case CBP will release the information as soon as possible after issuance of the notice of detention. The limited importation information CBP will disclose to the owner of the mark consists of:

(i) The date of importation;

(ii) The port of entry;

(iii) The description of the merchandise, for merchandise not yet detained, from the paper or electronic equivalent of the entry (as defined in § 142.3(a)(1) or (b) of this chapter), the CBP Form 7512, cargo manifest, advanceelectronic information or other entry document as appropriate, or, for detained merchandise, from the notice of detention;

(iv) The quantity, for merchandise not yet detained, as declared on the paper or electronic equivalent of the entry (as defined in § 142.3(a)(1) or (b) of this chapter), the CBP Form 7512, cargo manifest, advance electronic information, or other entry document as appropriate, or, for detained merchandise, from the notice of detention; and

(v) The country of origin of the merchandise.

(5) *Disclosure to owner of the mark of redacted photographs, images and samples.* Notwithstanding the notice and seven business day response procedure of paragraph (b)(2) of this section, CBP may, in order to obtain assistance in determining whether an imported article bears a counterfeit mark and at any time after presentation of the merchandise for examination, provide to the owner of the mark photographs, images, or a sample of the suspect merchandise or its retail packaging (including labels), provided that identifying information has been removed, obliterated, or otherwise obscured. Identifying information includes, but is not limited to, serial numbers, dates of manufacture, lot codes, batch numbers, universal product codes, the name or address of the manufacturer, exporter, or importer of the merchandise, or any mark that could reveal the name or address of the manufacturer, exporter, or importer of the merchandise, in alphanumeric or other formats. CBP may release to the owner of the mark a sample under this paragraph when the owner furnishes to CBP a bond in the form and amount specified by CBP, conditioned to indemnify the importer or owner of the imported article against any loss or damage resulting from the furnishing of the sample by CBP to the owner of the mark. CBP may demand the return of the sample at any time. The owner of the mark must return the sample to CBP upon demand or at the conclusion of any examination, testing, or similar procedure performed on the sample. In the event that the sample is damaged, destroyed, or lost while in the possession of the owner of the mark, the owner must, in lieu of return of the sample, certify to CBP that: ''The sample described as [insert description] and provided pursuant to 19 CFR 133.21(b)(5) was (damaged/destroyed/lost) during examination, testing, or other use.''

(c) *Conditions of disclosure to owner of the mark of information appearing on detained merchandise and/or its retail packaging, including unredacted photographs, images and samples*—(1) *Disclosure for limited purpose of assisting CBP in counterfeit mark determinations.* In order to obtain assistance in determining whether an imported article bears a counterfeit mark, CBP may disclose to the owner of the mark, prior to seizure, information appearing on the merchandise and/or its retail packaging (including labels), unredacted photographs or images of the merchandise and/or its retail packaging in its condition as presented for examination, or an unredacted sample of the imported merchandise and/or its retail packaging in its condition as presented for examination, in accordance with paragraphs (b)(2)(ii) and (3) of this section. Upon release of such information, photographs, images, or samples, CBP will notify the owner of the mark that some or all of the information being released may be subject to the protections of the Trade Secrets Act, and that CBP is only disclosing the information to the owner of the mark for the purpose of assisting CBP in determining whether the merchandise bears a counterfeit mark.

(2) *Bond.* CBP may release to the owner of the mark a sample under paragraphs (b)(2)(ii) and (3) of this section when the owner furnishes to CBP a bond in the form and amount specified by CBP, conditioned to indemnify the importer or owner of the imported article against any loss or damage resulting from the furnishing of the sample by CBP to the owner of the mark. CBP may demand the return of the sample at any time. The owner of the mark must return the sample to CBP upon demand or at the conclusion of any examination, testing, or similar procedure performed on the sample. In the event that the sample is damaged, destroyed, or lost while in the possession of the owner of the mark, the owner must, in lieu of return of the sample, certify to CBP that: ''The sample described as [insert description] and provided pursuant to 19 CFR 133.21(c) was (damaged/destroyed/lost) during examination, testing, or other use.''

(d) *Disclosure to importer of unredacted photographs, images, and samples.* CBP will disclose to the importer unredacted photographs, images, or an unredacted sample of imported merchandise suspected of bearing a counterfeit mark at any time after the merchandise is presented to CBP for examination. CBP may demand the return of the sample at any time. The importer must return the sample to CBP upon demand or at the conclusion of any examination, testing, or similar procedure performed on the sample. In the event that the sample is damaged, destroyed, or lost while in the possession of the importer, the importer must, in lieu of return of the sample, certify to CBP that: ''The sample described as [insert description] and provided pursuant to 19 CFR 133.21(d) was (damaged/destroyed/lost) during examination, testing, or other use.''

(e) *Seizure and disclosure to owner of the mark of comprehensive importation information.* Upon a determination by CBP, made any time after the merchandise has been presented for examination, that an article of domestic or foreign manufacture imported into the United States bears a counterfeit mark, CBP will seize such merchandise and, in the absence of the written consent of the owner of the mark, forfeit the seized merchandise in accordance with the customs laws. When merchandise is seized under this section, CBP will disclose to the owner of the mark the following comprehensive importation information, if available, within 30 business days from the date of the notice of the seizure:

(1) The date of importation;

(2) The port of entry;

(3) The description of the merchandise from the notice of seizure;

(4) The quantity as set forth in the notice of seizure;

(5) The country of origin of the merchandise;

(6) The name and address of the manufacturer;

(7) The name and address of the exporter; and

(8) The name and address of the importer.

(f) *Disclosure to owner of the mark, following seizure, of unredacted photographs, images, and samples.* At any time following a seizure of merchandise bearing a counterfeit mark under this section, and upon receipt of a proper request from the owner of the mark, CBP may provide, if available, photographs, images, or a sample of the seized merchandise and its retail packaging, in its condition as presented for examination, to the owner of the mark. To obtain a sample under this paragraph, the owner of the mark must furnish to CBP a bond in the form and amount specified by CBP, conditioned to indemnify the importer or owner of the imported article against any loss or damage resulting from the furnishing of the sample by CBP to the owner of the mark. CBP may demand the return of the sample at any time. The owner of the mark must return the sample to CBP upon demand or at the conclusion of the examination, testing, or other use in pursuit of a related private civil remedy for infringement. In the event that the sample is damaged, destroyed, or lost while in the possession of the owner of the mark, the owner must, in lieu of return of the sample, certify to CBP that: ''The sample described as [insert description] and provided pursuant to 19 CFR 133.21(f) was (damaged/destroyed/lost) during examination, testing, or other use.''

* * * * *

PART 151—EXAMINATION, SAMPLING, AND TESTING OF MERCHANDISE

■ 3. The general authority citation for part 151 continues to read as follows:

Authority: 19 U.S.C. 66, 1202 (General Note 3(i) and (j), Harmonized Tariff Schedule of the United States (HTSUS), 1624;

* * * * *

§ 151.16 [Amended]

■ 4. Section 151.16(a) is amended by removing the words, ''imports of articles bearing counterfeit marks or suspected counterfeit marks,''.

R. Gil Kerlikowske,

Commissioner, U.S. Customs and Border Protection.

Approved: September 15, 2015.

Timothy E. Skud,

Deputy Assistant Secretary of the Treasury.

[FR Doc. 2015–23543 Filed 9–17–15; 8:45 am]

BILLING CODE 9111–14–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 117

[Docket No. USCG–2015–0046]

RIN 1625–AA09

Drawbridge Operation Regulation; Snake Creek, Islamorada, FL

AGENCY: Coast Guard, DHS.

ACTION: Temporary interim rule and request for comments.

SUMMARY: The Coast Guard is modifying the operating schedule that governs the Snake Creek Bridge across Snake Creek, Islamorada, FL. This temporary interim rule will change the drawbridge operation schedule to determine whether a permanent change to the schedule is needed. This temporary interim rule will allow Snake Creek Bridge to open on signal, except that from 8 a.m. to 6 p.m., the draw need open only on the hour. The Bridge owner, Florida Department of Transportation, and local officials requested this action to assist in reducing vehicle traffic caused by frequent bridge openings.

DATES: This temporary interim rule will be effective from 8 a.m. on September 18, 2015 to 6 p.m. on May 10, 2016.

Comments and related material must reach the Coast Guard on or before January 15, 2016. Requests for public meetings must be received by the Coast Guard on or before November 1, 2015.

ADDRESSES: You may submit comments identified by docket number USCG–2015–0046 using any one of the following methods:

(1) *Federal eRulemaking Portal: http://www.regulations.gov.*

(2) *Fax:* 202–493–2251.

(3) *Mail or Delivery:* Docket Management Facility (M–30), U.S. Department of Transportation, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590–0001. Deliveries accepted between 9 a.m. and 5 p.m., Monday through Friday, except federal holidays. The telephone number is 202–366–9329.

See the ''Public Participation and Request for Comments'' portion of the **SUPPLEMENTARY INFORMATION** section below for instructions on submitting comments. To avoid duplication, please use only one of these methods.

FOR FURTHER INFORMATION CONTACT: If you have questions on this temporary interim rule, call or email Coast Guard Sector Key West Waterways Management Division; telephone 305–292–8772, email *D07-DG-SECKW-WaterwaysManagement@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Cheryl Collins, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

CFR Code of Federal Regulations
DHS Department of Homeland Security
FR Federal Register
§ Section Symbol
U.S.C. United States Code

A. Public Participation and Request for Comments

We encourage you to participate in this rulemaking by submitting comments and related materials. All comments received will be posted, without change, to *http://www.regulations.gov* and will include any personal information you have provided.

1. Submitting Comments

If you submit a comment, please include the docket number for this rulemaking (USCG–2015–0046), indicate the specific section of this document to which each comment applies, and give the reason for each suggestion or recommendation. You may submit your comments and material online, or by fax, mail or hand delivery, but please use only one of these means. If you submit a comment online via *http://www.regulations.gov,* it will be considered received by the Coast Guard when you successfully transmit the comment. If you fax, hand deliver, or mail your comment, it will be considered as having been received by the Coast Guard when it is received at the Docket Management Facility. We recommend that you include your name and a mailing address, an email address, or a phone number in the body of your document so that we can contact you if we have questions regarding your submission.

To submit your comment online, go to *http://www.regulations.gov,* type the docket number [USCG–2015–0046] in the ''SEARCH'' box and click ''SEARCH.'' Click on ''Submit a Comment'' on the line associated with this rulemaking. If you submit your comments by mail or hand delivery, submit them in an unbound format, no larger than 8½ by 11 inches, suitable for copying and electronic filing. If you submit them by mail and would like to know that they reached the Facility, please enclose a stamped, self-addressed postcard or envelope. We will consider all comments and material received during the comment period and may change this rule based on your comments.

2. Viewing Comments and Documents

To view comments, as well as documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* type the docket number (USCG–2015–0046) in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

3. Privacy Act

Anyone can search the electronic form of all 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 a Privacy Act notice regarding our public dockets in the January 17, 2008, issue of the **Federal Register** (73 FR 3316).

4. Public Meeting

We do not now plan to hold a public meeting. But you may submit a request for one on or before November 1, 2015, using one of the methods specified under **ADDRESSES**. Please explain why one would be beneficial. If we determine that one would aid this rulemaking, we will hold one at a time and place announced by a later notice in the **Federal Register**.

Regulatory History and Information

On March 27, 2015, we published a test deviation entitled ''Drawbridge Operation Regulations; Snake Creek, Islamorada, FL'' in the **Federal Register** (80 FR 16280). The comment period for the test deviation remains open until September 14, 2015.

The Coast Guard is issuing this temporary interim rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because delaying an amendment to the Snake Creek Bridge schedule would be impracticable and contrary to public interest. Pursuant to the temporary deviation published on March 27, 2015, the Snake Creek Bridge operating schedule was modified to determine if vehicular traffic congestion could be reduced while accommodating the reasonable needs of navigation. While the comment period for that deviation remains open, the Coast Guard is implementing this rule and seeks additional comment because the test deviation did not offer insight on the impacts of an alternate operating schedule during fall or winter months. Preliminary evidence shows that the revised schedule is beneficial to the commuting public and reverting to the schedule published in 33 CFR 117.331 may not be necessary to provide for the reasonable needs of navigation on Snake Creek.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register**for the same reasons discussed above.

B. Basis and Purpose

The Snake Creek Bridge in Islamorada, Florida has a vertical clearance of 27 feet in the closed position. The normal operating schedule as published in 33 CFR 117.331 is as follows: The draw of the Snake Creek Bridge, at Islamorada, Florida, shall open on signal, except that from 8 a.m. to 4 p.m., the draw need open only on the hour and half-hour. This schedule has been in effect since 2001.

The Bridge owner, Florida Department of Transportation, and local officials requested a change in the operating schedule to assist in reducing vehicle traffic caused by frequent bridge openings.

The Coast Guard initiated a test of a new schedule for the Snake Creek Bridge that was based on the following input:

1. As reported by village and city councils, vehicle traffic near the Snake Creek Bridge has negatively impacted Islamorada and surrounding communities during peak vehicle traffic time periods. A temporary deviation initiated a test of a new bridge operation schedule to reduce vehicle traffic caused by bridge openings.

2. On January 8–10, 2013, the Florida Department of Transportation conducted a traffic monitoring study 1400 feet south of the Snake Creek Bridge on US–1. The study found peak traffic volumes occurring at 8:45 a.m. and between 12:15 p.m. and 3:15 p.m. By reducing the number of scheduled openings between 8 a.m. and 6 p.m., this rule seeks to reduce vehicle traffic on US–1 while maintaining the reasonable needs of navigation on Snake Creek.

The types of vessels navigating Snake Creek include sport fishing vessels and catamaran sailboats.

During the test deviation, vessels signaled the bridge to open on the top of the hour from 8 a.m. to 6 p.m.

Any vessel that can safely transit under the Snake Creek Bridge while closed may continue to navigate under the bridge during this deviation.

Vessel operators may also consider the use of Channel Five, a navigable channel above Long Key, Florida 5.7 nautical miles southwest of Snake Creek Bridge. The fixed US–1 bridge across Channel Five has a vertical clearance of 65 feet.

C. Discussion of the Temporary Interim Rule

A test deviation published on March 27, 2015 allowed the Snake Creek Bridge to remain closed with the exception of on-demand openings once an hour schedule between 8 a.m. and 6 p.m. seven days a week. The deviation called for on-demand openings at all other times. The Coast Guard is initiating this temporary interim rule to allow the time necessary to review the impacts of the test schedule and how it will impact all modes of traffic during seasonal traffic.

Comments on the temporary deviation as well as any others received during the temporary interim rule comment period may be used to determine if a final rule should be implemented to modify the operating schedule.

D. Regulatory Analyses

We developed this temporary interim rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on these statutes or executive orders.

1. Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders. This rule is not a significant regulatory action because it allows for openings every hour and meets the reasonable needs of navigation while helping to decongest vehicular traffic on US–1. Vessels capable of transiting under the Bridge may do so at any time.

2. Impact on Small Entities

The Regulatory Flexibility Act of 1980 (RFA), 5 U.S.C. 601–612, as amended, requires federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

This action will not have a significant economic impact on a substantial number of small entities because it will allow for once an hour openings and vessels that can safely transit under the bridge may do so at any time.

3. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT,** above.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

4. Collection of Information

This rule calls for no new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has 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. We have analyzed this rule under that Order and have determined that it does not have implications for federalism.

6. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

7. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

8. Taking of Private Property

This rule will not cause a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

9. Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that might disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This rule is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guides the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have made a determination that this action is one of a category of actions which do not individually or cumulatively have a significant effect on the human environment. This rule simply promulgates the operating regulations or procedures for drawbridges. This rule is categorically excluded, under figure 2–1, paragraph (32)(e), of the Instruction.

Under figure 2–1, paragraph (32)(e), of the Instruction, an environmental analysis checklist and a categorical exclusion determination are not required for this rule.

List of Subjects in 33 CFR Part 117

Bridges.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 117 as follows:

PART 117—DRAWBRIDGE OPERATION REGULATIONS

■ 1. The authority citation for part 117 continues to read as follows:

Authority: 33 U.S.C. 499; 33 CFR 1.05–1; Department of Homeland Security Delegation No. 0170.1.

■ 2. Effective 8 a.m. on September 18, 2015 to 6 p.m. on May 10, 2016, suspend § 117.331 and add § 117.T331 to read as follows:

§ 117.T331 Snake Creek.

The draw of the Snake Creek Bridge, at Islamorada, Florida will open on signal, except that from 8 a.m. to 6 p.m., the draw need open only on the hour.

Dated: September 8, 2015.

S. A. Buschman,

Rear Admiral, U.S. Coast Guard, Commander, Seventh Coast Guard District.

[FR Doc. 2015–23537 Filed 9–17–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2015–0777]

RIN 1625–AA00

Safety Zone; Kaskaskia River MM 28 to 29; New Athens, IL

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone for all waters of the Kaskaskia River, surface to bottom, between mile 28 and 29. This temporary safety zone is necessary to protect persons and property from potential damage and safety hazards during the New Athens Drag Boat Race. During the period of enforcement, entry into this safety zone is prohibited unless specifically authorized by the Captain of the Port (COTP) Upper Mississippi River or other designated representative.

DATES: This rule is effective from 8:00 a.m. until 6:00 p.m. on September 19, 2015 and September 20, 2015. This rule will be enforced with actual notice from 8:00 a.m. until 6:00 p.m. on September 19, 2015 and September 20, 2015.

ADDRESSES: Documents mentioned in this preamble are part of docket USCG–2015–0777. To view documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* type the docket number in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email LCDR Sean Peterson, Chief of Prevention, Sector Upper Mississippi River U.S. Coast Guard; telephone (314) 269–2332, email *Sean.M.Peterson@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Cheryl Collins, Program Manager, Docket Operations, telephone (202) 366–9826.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR Federal Register
NPRM Notice of Proposed Rulemaking

A. Regulatory History and Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule. Providing a full notice period is contrary to the public interest as it would delay the effectiveness of the temporary safety zone until after the planned event. Immediate action is needed to protect vessels and the public from the safety hazards associated with this high speed race event on the Kaskaskia River in New Athens, IL. Completing the full NPRM process is unnecessary due to the fact that there is minimal commercial traffic in the area and that notices will be made using Broadcast Notice to Mariners and Local Notice to Mariners. Mariners will have the ability to request entrance into the zone by contacting the COTP during the closure period. These requests will be handled on a case by case basis. Additionally, a delay to the effective date for this safety zone would be contrary to public interest because it would interfere with the planned race and the contractual obligations related to this event, and it would put the safety of the spectators and participants of the event at risk.

For the same reasons, under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this rule effective less than 30 days after publication in the **Federal Register.** Delaying the effective date of the rule is contrary to the public interest as it would delay the effectiveness of the temporary safety zone until after the planned event.

B. Basis and Purpose

The legal basis and authorities for this rule are found in 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation no. 0170.1, which collectively authorize the Coast Guard to establish and define safety zones.

The Kentucky Drag Boat Association's annual New Athens Drag Boat Race is scheduled for September 19 and 20, 2015. The event is listed in Table 2 of 33 CFR 100.801 number seven for the second weekend in September; however, the event is being held on the third weekend of September this year. The race will feature inboard, outboard, and jet-propelled vessels competing on a closed course on the Kaskaskia River between miles 28 and 29. The Coast Guard determined that a safety zone is necessary to keep persons and property clear of any potential hazards associated with the race.

C. Discussion of the Final Rule

The Coast Guard is establishing a temporary safety zone from 8:00 a.m. to 6:00 p.m. on September 19, 2015 and September 20, 2015, for the New Athens Drag Boat Race. The event will take place on the Kaskaskia River and the safety zone will include all waters of the Kaskaskia River between miles 28 and 29. The Coast Guard will enforce the temporary safety zone and may be assisted by other federal, state and local agencies and the Coast Guard Auxiliary. During the periods of enforcement, no vessels may transit into, through, or remain within this Coast Guard safety zone closure area. Deviation from this safety zone may be requested by contacting the COTP Upper Mississippi River or other designated representative. They may be contacted on VHF–FM Channel 16, or through Coast Guard Sector Upper Mississippi at 314–269–2332. Deviations will be considered on a case-by case basis.

D. Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on these statutes and executive orders.

1. Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders. This temporary final rule establishes a safety zone that will be enforced for a limited time period. During the enforcement period, vessels are prohibited from entering into or remaining within the safety zone unless specifically authorized by the COTP Upper Mississippi River or other designated representative. Based on the location, limited safety zone size, and short duration of the enforcement period, the impacts on routine navigation are expected to be minimal. Additionally, notice of this safety zone or any changes in the planned schedule will be made via Broadcast Notice to Mariners and Local Notices to Mariners. Deviation from this rule may be requested from the COTP Upper Mississippi River and will be considered on a case-by-case basis.

2. Impact on Small Entities

The Regulatory Flexibility Act of 1980 (RFA), 5 U.S.C. 601–612, as amended, requires federal agencies to consider the potential impact of regulations on small entities during rulemaking. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities.

This rule will affect the following entities, some of which may be small entities: the owners or operators of vessels intending to transit the Kaskaskia River between mile markers 28 and 29 from 8:00 a.m. to 6:00 p.m. on September 19, 2015 and September 20, 2015.

This safety zone will not have a significant economic impact on a substantial number of small entities for the following reason: this rule will be enforced for a short amount of time each day and commercial traffic is minimal in this area.

3. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT,** above.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

4. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has 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. We have analyzed this rule under that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

7. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

8. Taking of Private Property

This rule will not cause a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

9. Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA)(42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves establishment of a temporary safety zone to protect persons and property from potential hazards associated with the scheduled New Athens Drag Boat Race taking place on the Kaskaskia River. This rule is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. A new temporary § 165.T08–0777 is added to read as follows:

§ 165.T08–0777 Safety Zone; Kaskaskia River between MM 28 and 29; New Athens, IL.

(a) *Location.* The following area is a safety zone: All waters of the Kaskaskia River between MM 28 and 29, New Athens, IL.

(b) *Effective and enforcement period.* This rule is effective from 8:00 a.m. until 6:00 p.m. on September 19, 2015 and September 20, 2015. This rule will be enforced with actual notice from 8:00 a.m. until 6:00 p.m. on September 19, 2015 and September 20, 2015.

(c) *Regulations.* (1) In accordance with the general regulations in § 165.23, entry into, movement within, or departure from this zone is prohibited unless authorized by the COTP Upper Mississippi River or a designated representative.

(2) Persons or vessels requiring entry into, departure from, or movement within a regulated area must request permission from the COTP Upper Mississippi River or a designated representative. They may be contacted on VHF–FM Channel 16, or through Coast Guard Sector Upper Mississippi River at (314) 269–2332.

(3) All persons and vessels shall comply with the instruction of the COTP Upper Mississippi River and designated on-scene personnel.

(d) *Informational broadcasts.* The COTP Upper Mississippi River or a designated representative will inform the public through Local Notice to Mariners of the enforcement period for the safety zone as well as any changes in the planned and published dates and times of enforcement.

Dated: August 13, 2015.

M. L. Malloy,

Captain, U.S. Coast Guard, Captain of the Port Sector Upper Mississippi River.

[FR Doc. 2015–23535 Filed 9–17–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2015–0833]

RIN 1625–AA00

Safety Zone; Saint-Gobain Performance Plastics Celebration Fireworks; Lake Erie, Cleveland, OH

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone in Lake Erie, Cleveland, OH. This safety zone is intended to restrict vessels from a portion of Lake Erie during the Saint-Gobain Performance Plastics Celebration fireworks display. This temporary safety zone is necessary to protect mariners and vessels from the navigational hazards associated with a fireworks display.

DATES: This rule will be effective from 9:15 p.m. until 10:05 p.m. on September 19, 2015.

ADDRESSES: Documents mentioned in this preamble are part of docket [USCG–2015–0833]. To view documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* type the docket number in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rulemaking. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call LT Stephanie Pitts, Chief of Waterways Management, U.S. Coast Guard Marine Safety Unit Cleveland; telephone 216–937–0128. If you have questions on viewing the docket, call Ms. Cheryl Collins, Program Manager, Docket Operations, telephone 202–366–9826 or 1–800–647–5527.

SUPPLEMENTARY INFORMATION:

Table of Acronyms

DHS Department of Homeland Security
FR Federal Register
NPRM Notice of Proposed Rulemaking
TFR Temporary Final Rule

A. Regulatory History and Information

The Coast Guard is issuing this temporary final rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule because doing so would be impracticable and contrary to the public interest. The final details for this event were not known to the Coast Guard until there was insufficient time remaining before the event to publish an NPRM. Thus, delaying the effective date of this rule to wait for a comment period to run would be both impracticable and contrary to the public interest because it would inhibit the Coast Guard's ability to protect spectators and vessels from the hazards associated with a maritime fireworks display.

Under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making this temporary rule effective less than 30 days after publication in the **Federal Register**. For the same reasons discussed in the preceding paragraph, waiting for a 30 day notice period to run would be impracticable and contrary to the public interest.

B. Basis and Purpose

The legal basis and authorities for this rule are found in 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; and Department of Homeland Security Delegation No. 0170.1, which collectively authorize the

Coast Guard to establish and define regulatory safety zones.

Between 9:15 p.m. and 10:05 p.m. on September 19, 2015, a fireworks display will be held on the shoreline of Lake Erie in Cleveland, OH. It is anticipated that numerous vessels will be in the immediate vicinity of the launch point. The Captain of the Port Buffalo has determined that such a launch proximate to a gathering of watercraft poses a significant risk to public safety and property. Such hazards include premature and accidental detonations, dangerous projectiles, and falling or burning debris.

C. Discussion of the Final Rule

With the aforementioned hazards in mind, the Captain of the Port Buffalo has determined that this temporary safety zone is necessary to ensure the safety of spectators and vessels during the Saint-Gobain Performance Plastics Celebration fireworks display. This zone will be effective and enforced from 9:15 p.m. until 10:05 p.m. on September 19, 2015. This zone will encompass all waters of Lake Erie; Cleveland, OH within a 280-foot radius of position 41° 30′34.23″ N. and 81°41′56.3″ W. (NAD 83).

Entry into, transiting, or anchoring within the safety zone is prohibited unless authorized by the Captain of the Port Buffalo or his designated on-scene representative. The Captain of the Port or his designated on-scene representative may be contacted via VHF Channel 16.

D. Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders related to rulemaking. Below we summarize our analyses based on these statutes and executive orders.

1. Regulatory Planning and Review

This rule is not a significant regulatory action under section 3(f) of Executive Order 12866, Regulatory Planning and Review, as supplemented by Executive Order 13563, Improving Regulation and Regulatory Review, and does not require an assessment of potential costs and benefits under section 6(a)(3) of Executive Order 12866 or under section 1 of Executive Order 13563. The Office of Management and Budget has not reviewed it under those Orders.

We conclude that this rule is not a significant regulatory action because we anticipate that it will have minimal impact on the economy, will not interfere with other agencies, will not adversely alter the budget of any grant or loan recipients, and will not raise any novel legal or policy issues. The safety zone created by this rule will be relatively small and enforced for a relatively short time. Also, the safety zone is designed to minimize its impact on navigable waters. Under certain conditions, moreover, vessels may still transit through the safety zone when permitted by the Captain of the Port.

2. Impact on Small Entities

Under the Regulatory Flexibility Act (5 U.S.C. 601–612), we have considered the impact of this rule on small entities. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. This rule will affect the following entities, some of which might be small entities: The owners or operators of vessels intending to transit or anchor in a portion of Lake Erie; Cleveland, OH on the evening of September 19, 2015.

This safety zone will not have a significant economic impact on a substantial number of small entities for the following reasons: This safety zone would be effective, and thus subject to enforcement, for only 50 minutes late in the day. Traffic may be allowed to pass through the zone with the permission of the Captain of the Port. The Captain of the Port can be reached via VHF channel 16. Before the enforcement of the zone, we would issue local Broadcast Notice to Mariners.

3. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section above.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

4. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has 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. We have analyzed this rule under that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

The Coast Guard respects the First Amendment rights of protesters. Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places, or vessels.

7. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such an expenditure, we do discuss the effects of this rule elsewhere in this preamble.

8. Taking of Private Property

This rule will not cause a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

9. Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of

Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves the establishment of a safety zone and, therefore it is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. An environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. Section 165.T09–0833 is added to read as follows:

§ 165.T09–0833 Safety Zone; Saint-Gobain Performance Plastics Celebration Fireworks, Lake Erie; Cleveland, OH.

(a) *Location.* This zone will encompass all waters of Lake Erie; Cleveland, OH within a 280-foot radius of position 41°30′34.23″ N. and 81°41′56.3″ W. (NAD 83).

(b) *Effective and Enforcement Period.* This regulation is effective and will be enforced on September 19, 2015 from 9:15 p.m. until 10:05 p.m.

(c) *Regulations.* (1) In accordance with the general regulations in § 165.23 of this part, entry into, transiting, or anchoring within this safety zone is prohibited unless authorized by the Captain of the Port Buffalo or his designated on-scene representative.

(2) This safety zone is closed to all vessel traffic, except as may be permitted by the Captain of the Port Buffalo or his designated on-scene representative.

(3) The ''on-scene representative'' of the Captain of the Port Buffalo is any Coast Guard commissioned, warrant or petty officer who has been designated by the Captain of the Port Buffalo to act on his behalf.

(4) Vessel operators desiring to enter or operate within the safety zone shall contact the Captain of the Port Buffalo or his on-scene representative to obtain permission to do so. The Captain of the Port Buffalo or his on-scene representative may be contacted via VHF Channel 16. Vessel operators given permission to enter or operate in the safety zone must comply with all directions given to them by the Captain of the Port Buffalo, or his on-scene representative.

Dated: August 27, 2015.

B. W. Roche,

Captain, U.S. Coast Guard, Captain of the Port Buffalo.

[FR Doc. 2015–23536 Filed 9–17–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

33 CFR Part 165

[Docket Number USCG–2015–0570]

RIN 1625–AA00

Safety Zone; 520 Bridge Construction, Lake Washington, Seattle, WA

AGENCY: Coast Guard, DHS.

ACTION: Temporary final rule.

SUMMARY: The Coast Guard is establishing a temporary safety zone on Lake Washington around the east span of the 520 Bridge in Seattle, Washington due to ongoing construction. The safety zone is necessary to ensure the safety of the maritime public and workers involved in the bridge construction when construction barges are located in the east span of the bridge. The safety zone will prohibit any person or vessel from entering or remaining in the safety zone unless authorized by the Captain of the Port or his Designated Representative.

DATES: This rule is effective without actual notice from September 18, 2015 through October 5, 2015. For the purposes of enforcement, actual notice will be used from September 5, 2015 until September 18, 2015.

ADDRESSES: To view documents mentioned in this preamble as being available in the docket, go to *http://www.regulations.gov,* type USCG–2015–0570 in the ''SEARCH'' box and click ''SEARCH.'' Click on Open Docket Folder on the line associated with this rule. You may also visit the Docket Management Facility in Room W12–140 on the ground floor of the Department of Transportation West Building, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

FOR FURTHER INFORMATION CONTACT: If you have questions on this rule, call or email Ryan Griffin, Waterways Management Division, Coast Guard Sector Puget Sound; telephone (206) 217–6051, email *SectorPugetSoundWWM@uscg.mil.* If you have questions on viewing or submitting material to the docket, call Ms. Cheryl Collins, Program Manager, Docket Operations, telephone 202–366–9826.

SUPPLEMENTARY INFORMATION:

I. Table of Abbreviations

CFR Code of Federal Regulations

DHS Department of Homeland Security
E.O. Executive order
FR Federal Register
NPRM Notice of proposed rulemaking
Pub. L. Public Law
§ Section
U.S.C. United States Code

II. Background Information and Regulatory History

The Coast Guard is issuing this temporary rule without prior notice and opportunity to comment pursuant to authority under section 4(a) of the Administrative Procedure Act (APA) (5 U.S.C. 553(b)). This provision authorizes an agency to issue a rule without prior notice and opportunity to comment when the agency for good cause finds that those procedures are ''impracticable, unnecessary, or contrary to the public interest.'' Under 5 U.S.C. 553(b)(B), the Coast Guard finds that good cause exists for not publishing a notice of proposed rulemaking (NPRM) with respect to this rule exists as notice would be impracticable due to the unexpected construction delays. It would be impracticable to publish an NPRM as the safety zone must be in effect by September 5, 2015

We are issuing this rule, and under 5 U.S.C. 553(d)(3), the Coast Guard finds that good cause exists for making it effective less than 30 days after publication in the **Federal Register**. Delaying the effective date of this rule would be impracticable because immediate action is needed to respond to the potential safety hazards associated with the construction of the east span of the 520 Bridge.

III. Legal Authority and Need for Rule

Ongoing construction on the 520 Bridge in Seattle, Washington is creating hazardous conditions around the construction. A safety zone is necessary to ensure the safety of the maritime public and workers involved in the bridge construction when construction barges are located in the east span of the bridge. As construction was originally intended to be completed by September, a temporary final rule was established on June 22, 2015 through September 4, 2015 to protect the construction personal, maritime public, and the marine environment around the east span of the 520 bridge during times of construction operations (see 80 FR 38944, July 8, 2015). However, as construction has needed to continue, a new safety zone is needed to ensure safety.

The Coast Guard is issuing this rule under authority in 33 U.S.C. 1231. The Captain of the Port Puget sound (COTP) has determined that potential hazards associated with bridge construction starting September 5, 2015 will be a safety concern for anyone within a 100-yard radius of the 520 Bridge east span construction operations. This rule is needed to protect personnel, vessels, and the marine environment in the navigable waters within the safety zone while the bridge is being repaired.

IV. Discussion of the Rule

The safety zone established in this rule encompasses all waters within 100 yards of the east span of the 520 Bridge, located on Lake Washington and is effective from September 5, 2015 through October 2, 2015 when a construction barge is present in the safety zone. Vessels wishing to enter the safety zone must request permission to do so from the Captain of the Port by contacting the Joint Harbor Operations Center at 206–217–6001 or VHF Channel 16. If permission for entry is granted, vessels must proceed at a minimum speed for safe navigation.

V. Regulatory Analyses

We developed this rule after considering numerous statutes and executive orders (E.O.s) related to rulemaking. Below we summarize our analyses based on a number of these statutes and E.O.s, and we discuss First Amendment rights of protestors.

1. Regulatory Planning and Review

E.O.s 12866 and 13563 direct agencies to assess the costs and benefits of available regulatory alternatives and, if regulation is necessary, to select regulatory approaches that maximize net benefits. E.O. 13563 emphasizes the importance of quantifying both costs and benefits, of reducing costs, of harmonizing rules, and of promoting flexibility. This rule has not been designated a ''significant regulatory action,'' under E.O. 12866. Accordingly, it has not been reviewed by the Office of Management and Budget.

This rule is not a significant regulatory action as the safety zone established by it is both limited in size and duration and there is an alternative route for vessels with an air draft that permits safe passage under the west span of the bridge.

2. Impact on Small Entities

The Regulatory Flexibility Act of 1980 (RFA), 5 U.S.C. 601–612, as amended, requires federal agencies to consider the potential impact of regulations on small entities during rulemaking. The term ''small entities'' comprises small businesses, not-for-profit organizations that are independently owned and operated and are not dominant in their fields, and governmental jurisdictions with populations of less than 50,000. The Coast Guard certifies under 5 U.S.C. 605(b) that this rule will not have a significant economic impact on a substantial number of small entities. This rule will affect the following entities, some of which may be small entities: Owners or operators of vessels intending to transit the safety zone. This safety zone will not have a significant economic impact on a substantial number of small entities for the reasons stated under paragraph D.1., Regulatory Planning and Review.

3. Assistance for Small Entities

Under section 213(a) of the Small Business Regulatory Enforcement Fairness Act of 1996 (Pub. L. 104–121), we want to assist small entities in understanding this rule. If the rule would affect your small business, organization, or governmental jurisdiction and you have questions concerning its provisions or options for compliance, please contact the person listed in the **FOR FURTHER INFORMATION CONTACT**, above.

Small businesses may send comments on the actions of Federal employees who enforce, or otherwise determine compliance with, Federal regulations to the Small Business and Agriculture Regulatory Enforcement Ombudsman and the Regional Small Business Regulatory Fairness Boards. The Ombudsman evaluates these actions annually and rates each agency's responsiveness to small business. If you wish to comment on actions by employees of the Coast Guard, call 1–888–REG–FAIR (1–888–734–3247). The Coast Guard will not retaliate against small entities that question or complain about this rule or any policy or action of the Coast Guard.

4. Collection of Information

This rule will not call for a new collection of information under the Paperwork Reduction Act of 1995 (44 U.S.C. 3501–3520).

5. Federalism

A rule has implications for federalism under Executive Order 13132, Federalism, if it has 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. We have analyzed this rule under that Order and determined that this rule does not have implications for federalism.

6. Protest Activities

The Coast Guard respects the First Amendment rights of protesters.

Protesters are asked to contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to coordinate protest activities so that your message can be received without jeopardizing the safety or security of people, places or vessels.

7. Unfunded Mandates Reform Act

The Unfunded Mandates Reform Act of 1995 (2 U.S.C. 1531–1538) requires Federal agencies to assess the effects of their discretionary regulatory actions. In particular, the Act addresses actions that may result in the expenditure by a State, local, or tribal government, in the aggregate, or by the private sector of $100,000,000 (adjusted for inflation) or more in any one year. Though this rule will not result in such expenditure, we do discuss the effects of this rule elsewhere in this preamble.

8. Taking of Private Property

This rule will not cause a taking of private property or otherwise have taking implications under Executive Order 12630, Governmental Actions and Interference with Constitutionally Protected Property Rights.

9. Civil Justice Reform

This rule meets applicable standards in sections 3(a) and 3(b)(2) of Executive Order 12988, Civil Justice Reform, to minimize litigation, eliminate ambiguity, and reduce burden.

10. Protection of Children

We have analyzed this rule under Executive Order 13045, Protection of Children from Environmental Health Risks and Safety Risks. This rule is not an economically significant rule and does not create an environmental risk to health or risk to safety that may disproportionately affect children.

11. Indian Tribal Governments

This rule does not have tribal implications under Executive Order 13175, Consultation and Coordination with Indian Tribal Governments, because it does not have a substantial direct effect on one or more Indian tribes, on the relationship between the Federal Government and Indian tribes, or on the distribution of power and responsibilities between the Federal Government and Indian tribes.

12. Energy Effects

This action is not a ''significant energy action'' under Executive Order 13211, Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use.

13. Technical Standards

This rule does not use technical standards. Therefore, we did not consider the use of voluntary consensus standards.

14. Environment

We have analyzed this rule under Department of Homeland Security Management Directive 023–01 and Commandant Instruction M16475.lD, which guide the Coast Guard in complying with the National Environmental Policy Act of 1969 (NEPA) (42 U.S.C. 4321–4370f), and have determined that this action is one of a category of actions that do not individually or cumulatively have a significant effect on the human environment. This rule involves implementation of regulations within 33 CFR part 165, applicable to safety zones on the navigable waterways. This zone will temporarily restrict vessel traffic from transiting the Indian River Bay along the shoreline of Long Neck, Delaware, in order to protect the safety of life and property on the waters for the duration of the fireworks display. This rule is categorically excluded from further review under paragraph 34(g) of Figure 2–1 of the Commandant Instruction. A preliminary environmental analysis checklist supporting this determination and a Categorical Exclusion Determination are available in the docket where indicated under **ADDRESSES**. We seek any comments or information that may lead to the discovery of a significant environmental impact from this rule.

List of Subjects in 33 CFR Part 165

Harbors, Marine safety, Navigation (water), Reporting and recordkeeping requirements, Security measures, Waterways.

For the reasons discussed in the preamble, the Coast Guard amends 33 CFR part 165 as follows:

PART 165—REGULATED NAVIGATION AREAS AND LIMITED ACCESS AREAS

■ 1. The authority citation for part 165 continues to read as follows:

Authority: 33 U.S.C. 1231; 50 U.S.C. 191; 33 CFR 1.05–1, 6.04–1, 6.04–6, and 160.5; Department of Homeland Security Delegation No. 0170.1.

■ 2. Add § 165.T13–290 to read as follows:

§ 165.T13–290 Safety Zone; 520 Bridge, Lake Washington; Seattle, WA.

(a) *Location.* The following area is designated as a safety zone: All waters within 100 yards of the east span of the 520 Bridge located on Lake Washington in Seattle, Washington.

(b) *Regulations.* In accordance with the general regulations in subpart C of this part, no person may enter the safety zone or bring or cause to be brought any vessel into the safety zone without permission of the Captain of the Port. Persons wishing to enter the safety zone must request permission from the Captain of the Port by contacting the Joint Harbor Operation Center at 206–217–6001 or VHF Channel 16. If permission for entry is granted, vessels must proceed at a minimum speed for safe navigation.

(c) *Dates.* This rule is effective from September 5, 2015 through October 2, 2015 when a construction barge is present inside the safety zone.

Dated: September 3, 2015.

M.W. Raymond,

Captain, U.S. Coast Guard, Captain of the Port Puget Sound.

[FR Doc. 2015–23526 Filed 9–17–15; 8:45 am]

BILLING CODE 9110–04–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R07–OAR–2015–0514; FRL–9933–97–Region 7]

Approval and Promulgation of Air Quality Implementation Plans for Designated Facilities and Pollutants; Missouri; Commercial and Industrial Solid Waste Incineration (CISWI) Units

AGENCY: Environmental Protection Agency.

ACTION: Direct final rule.

SUMMARY: The Environmental Protection Agency (EPA) is taking direct final action to approve revisions to the state plan for designated facilities and pollutants developed under sections 111(d) and 129 of the Clean Air Act for the State of Missouri. This direct final action will amend the state plan to include a new plan and associated rule implementing the emissions guidelines for Commercial and Industrial Solid Waste Incineration (CISWI) Units.

DATES: This direct final rule will be effective November 17, 2015, without further notice, unless EPA receives adverse comment by October 19, 2015. If EPA receives adverse comment, we will publish a timely withdrawal of the direct final rule in the **Federal Register** informing the public that the rule will not take effect.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R07–

OAR–2015–0514, by one of the following methods:

1. *www.regulations.gov.* Follow the on-line instructions for submitting comments.

2. *Email: higbee.paula@epa.gov.*

3. *Mail or Hand Delivery:* Paula Higbee, Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219.

Instructions: Direct your comments to Docket ID No. EPA–R07–OAR–2015–0514. EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.* 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.

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *i.e.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219. The Regional Office's official hours of business are Monday through Friday, 8:00 a.m. to 4:30 p.m., excluding legal holidays. The interested persons wanting to examine these documents should make an appointment with the office at least 24 hours in advance.

FOR FURTHER INFORMATION CONTACT: Paula Higbee, Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219 at 913–551–7028 or by email at *higbee.paula@epa.gov.*

SUPPLEMENTARY INFORMATION: Throughout this document ''we,'' ''us,'' or ''our'' refer to EPA. This section provides additional information by addressing the following:

I. Background
II. Analysis of State Submittal
III. What Action is EPA Taking?
IV. Statutory and Executive Order Reviews

I. Background

The Clean Air Act (CAA) requires that state regulatory agencies implement the emission guidelines and compliance times using a state plan developed under sections 111(d) and 129 of the CAA. Section 111(d) establishes general requirements and procedures on state plan submittals for the control of designated pollutants. Section 129 requires emission guidelines to be promulgated for all categories of solid waste incineration units, including CISWI units. Section 129 mandates that all plan requirements be at least as protective and restrictive as the promulgated emission guidelines. This includes fixed final compliance dates, fixed compliance schedules, and Title V permitting requirements for all affected sources. Section 129 also requires that state plans be submitted to EPA within one year after EPA's promulgation of the emission guidelines and compliance times.

On February 7, 2013, EPA finalized emission limitations for CISWI units and definitions for Non-Hazardous Secondary Materials (NHSM) that are Solid Waste, both under the same notice at 78 FR 9112. This notice was the final decision on the CISWI rule originally published March 21, 2011, and reconsidered after further public comments were solicited and received. The notice also included final amendments to the NHSM rule. The definition of solid waste in the NHSM rule determines whether a particular incinerator is covered under another incinerator rule.

The state submitted a negative declaration on May 9, 2011. Subsequently, the state found that they did have applicable units and therefore, the state issued a new rule and state plan to meet its obligations under this new Federal rule. The state rule, 10 CSR 10–6.161, for CISWI became effective on November 21, 2013. The associated state plan was issued concurrently with the new rule. The state's rule incorporates by reference the Federal rule.

II. Analysis of State Submittal

The emission guidelines and compliance times are codified in 40 CFR part 60, subpart DDDD. State plans must contain specific information and the legal mechanisms necessary to implement the emission guidelines and compliance times. The requirements are as follows:

- *Inventory of affected CISWI units, including those that have ceased operation but have not been dismantled.*
- *Inventory of emissions from affected CISWI units in Missouri.*
- *Compliance schedules for each affected CISWI unit with a final compliance date no later than February 7, 2018 or three (3) years after the effective date of state plan approval, whichever is earlier.*
- *Emission limitations, operator training and qualification requirements, a waste management plan, and operating limits for affected CISWI units that are at least as protective as the emission guidelines contained in Subpart DDDD.*
- *Performance testing, recordkeeping, and reporting requirements.*
- *Certification that the hearing on the State plan was held, a list of witnesses and organizational affiliations, if any, appearing at the hearing, and a brief written summary of each presenation or written submission.*
- *Provision for State progress reports to EPA.*
- *Identification of enforceable State mechanisms that were selected for implementing the emission guidelines of Subpart DDDD.*
- *Demonstration of Missouri's legal authority to carry out the sections 111(d) and 129 State plan.*

The state's plan was received on March 5, 2014, in accordance with the requirements for adoption and submittal of state plans for designated facilities in 40 CFR part 60, subpart B. The plan establishes emission limits for existing CISWI units, and provides for the implementation and enforcement of those limits. Missouri's plan includes all documentation that all of these requirements have been met. The emission limits, testing, monitoring, reporting and recordkeeping requirements, and other aspects of the Federal rule have been adopted. Missouri rule 10 CSR 10–6.161 contains the applicable requirements. The state provided evidence that it complied with the public notice and comment requirements of 40 CFR part 60, subpart DDDD.

III. What Action is EPA Taking?

Based on the rationale discussed aboved, EPA is taking direct final action to approve Missouri's March 5, 2014, submittal of its 111(d) plan for commercial and industrial solid waste incineration units. We are publishing this direct final rule without a prior proposed rule because we view this as a noncontroversial action and anticipate no adverse comment. However, in the ''Proposed Rules'' section of this **Federal Register**, we are publishing a separate document that will serve as the proposed rule to approve the revision to the 111(d) plan if adverse comments are received on this direct final rule. We will not institute a second comment period on this action. Any parties interested in commenting must do so at this time. For further information about commenting on this rule, see the **ADDRESSES** section of this document.

If EPA receives adverse comment, we will publish a timely withdrawal in the **Federal Register** informing the public that this direct final rule will not take effect. We will address all public comments in any subsequent final rule based on the proposed rule.

IV. Statutory and Executive Order Reviews

Under Executive Order 12866 (58 FR 51735, October 4, 1993), this action is not a ''significant regulatory action'' and therefore is not subject to review by the Office of Management and Budget. For this reason, this action is also not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001). This action merely approves state law as meeting Federal requirements and imposes no additional requirements beyond those imposed by state law. Accordingly, the Administrator certifies that this rule will not have a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*). Because this rule approves pre-existing requirements under state law and does not impose any additional enforceable duty beyond that required by state law, it does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4). This action is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications and will not impose substantial direct costs on tribal governments or preempt tribal law as specified by Executive Order 13175 (65 FR 67249, November 9, 2000). This action also does not have Federalism implications because it does not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132 (64 FR 43255, August 10, 1999). This action merely approves a state rule implementing a Federal requirement, and does not alter the relationship or the distribution of power and responsibilities established in the Act. This rule also is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997), because it approves a state rule implementing a Federal standard. In reviewing section 111(d)/129 plan submissions, EPA's role is to approve State choices, provided that they meet the criteria of the Act. In this context, in the absence of a prior existing requirement for the State to use voluntary consensus standards (VCS), EPA has no authority to disapprove a section 111(d)/129 plan submission for failure to use VCS. It would thus be inconsistent with applicable law for EPA, when it reviews a section 111(d)/129 plan submission, to use VCS in place of a section 111(d)/129 plan submission that otherwise satisfies the provisions of the Act. Thus, the requirements of section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) do not apply. This rule does not impose an information collection burden under the provisions of the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*).

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 United States. EPA will submit a report containing this action and other required information to the U.S. Senate, the U.S. House of Representatives, and the Comptroller General of the United States 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 not a ''major rule'' as defined by 5 U.S.C. 804(2).

Under section 307(b)(1) of the CAA, petitions for judicial review of this action must be filed in the United States Court of Appeals for the appropriate circuit by November 17, 2015. Filing a petition for reconsideration by the Administrator of this final rule does not affect the finality of this rule for the purposes of judicial review nor does it extend the time within which a petition for judicial review may be filed, and shall not postpone the effectiveness of such rule or action. This action approving Missouri's section 111(d)/129 plan revision for CISWI sources may not be challenged later in proceedings to enforce its requirements. (See section 307(b)(2)).

List of Subjects in 40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Commercial and industrial solid waste incineration units, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: September 3, 2015.

Becky Weber,

Acting Regional Administrator, Region 7.

For the reasons stated in the preamble, EPA amends 40 CFR part 62 as set forth below:

PART 62—APPROVAL AND PROMULGATION OF STATE PLANS FOR DESIGNATED FACILITIES AND POLLUTANTS

■ 1. The authority citation for part 62 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

Subpart AA—Missouri

■ 2. Revise § 62.6360 to read as follows:

Air Emissions From Existing Commercial and Industrial Solid Waste Incineration Units

§ 62.6360 Identification of plan.

(a) *Identification of plan.* The Missouri Department of Natural Resources approved this revision to the Missouri state plan section 111(d) for the purpose of adopting by reference subpart DDDD of part 62, the Commercial and Industrial Solid Waste Incineration (CISWI) rule, 10 CSR 10–6.161, which became effective on November 21, 2013. This revision was submitted on March 5, 2014.

(b) *Identification of sources.* The plan applies to existing commercial and industrial solid waste incineration (CISWI) units that commenced construction on or before November 30, 1999.

(c) The effective date of the amended plan is November 17, 2015.

[FR Doc. 2015–23390 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 180

[EPA–HQ–OPP–2015–0375; FRL–9933–02]

Fluensulfone; Pesticide Tolerances

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This regulation establishes a tolerance for residues of fluensulfone in or on tomato, paste. Makhteshim Agan of North America, Inc., doing business as ADAMA requested these tolerances under the Federal Food, Drug, and Cosmetic Act (FFDCA).

DATES: This regulation is effective September 18, 2015. Objections and requests for hearings must be received on or before November 17, 2015, and must be filed in accordance with the instructions provided in 40 CFR part 178 (see also Unit I.C. of the **SUPPLEMENTARY INFORMATION**).

ADDRESSES: The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2015–0375, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

FOR FURTHER INFORMATION CONTACT: Susan Lewis, Registration Division (7505P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; main telephone number: (703) 305–7090; email address: *RDFRNotices@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

You may be potentially affected by this action if you are an agricultural producer, food manufacturer, or pesticide manufacturer. The following list of North American Industrial Classification System (NAICS) codes is not intended to be exhaustive, but rather provides a guide to help readers determine whether this document applies to them. Potentially affected entities may include:

- Crop production (NAICS code 111).
- Animal production (NAICS code 112).
- Food manufacturing (NAICS code 311).
- Pesticide manufacturing (NAICS code 32532).

B. How can I get electronic access to other related information?

You may access a frequently updated electronic version of EPA's tolerance regulations at 40 CFR part 180 through the Government Printing Office's e-CFR site at *http://www.ecfr.gov/cgi-bin/text-idx?&c=ecfr&tpl=/ecfrbrowse/Title40/40tab_02.tpl.*

C. How can I file an objection or hearing request?

Under FFDCA section 408(g), 21 U.S.C. 346a, any person may file an objection to any aspect of this regulation and may also request a hearing on those objections. You must file your objection or request a hearing on this regulation in accordance with the instructions provided in 40 CFR part 178. To ensure proper receipt by EPA, you must identify docket ID number EPA–HQ–OPP–2015–0375 in the subject line on the first page of your submission. All objections and requests for a hearing must be in writing, and must be received by the Hearing Clerk on or before November 17, 2015. Addresses for mail and hand delivery of objections and hearing requests are provided in 40 CFR 178.25(b).

In addition to filing an objection or hearing request with the Hearing Clerk as described in 40 CFR part 178, please submit a copy of the filing (excluding any Confidential Business Information (CBI)) for inclusion in the public docket. Information not marked confidential pursuant to 40 CFR part 2 may be disclosed publicly by EPA without prior notice. Submit the non-CBI copy of your objection or hearing request, identified by docket ID number EPA–HQ–OPP–2015–0375, by one of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Do not submit electronically any information you consider to be CBI or other information whose disclosure is restricted by statute.
- *Mail:* OPP Docket, Environmental Protection Agency Docket Center (EPA/DC), (28221T), 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001.
- *Hand Delivery:* To make special arrangements for hand delivery or delivery of boxed information, please follow the instructions at *http://www.epa.gov/dockets/contacts.html.*

Additional instructions on commenting or visiting the docket, along with more information about dockets generally, is available at *http://www.epa.gov/dockets.*

II. Summary of Petitioned-For Tolerance

In the **Federal Register** of July 17, 2015 (80 FR 42462) (FRL–9929–13), EPA issued a document pursuant to FFDCA section 408(d)(3), 21 U.S.C. 346a(d)(3), announcing the filing of a pesticide petition (PP 5F8365) by Makhteshim Agan of North America, Inc., doing business as ADAMA, 3120 Highwoods Blvd., Suite 100, Raleigh, NC 27604. The petition requested that 40 CFR part 180 be amended by establishing tolerances for residues of the insecticide fluensulfone, 3,4,4-trifluoro-but-3-ene-1-sulfonic acid, in or on tomato, paste at 1.0 parts per million (ppm). That document referenced a summary of the petition prepared by ADAMA, the registrant, which is available in the docket, *http://www.regulations.gov.* There were no comments received in response to the notice of filing.

III. Aggregate Risk Assessment and Determination of Safety

Section 408(b)(2)(A)(i) of FFDCA allows EPA to establish a tolerance (the legal limit for a pesticide chemical residue in or on a food) only if EPA determines that the tolerance is ''safe.'' Section 408(b)(2)(A)(ii) of FFDCA defines ''safe'' to mean that ''there is a reasonable certainty that no harm will result from aggregate exposure to the pesticide chemical residue, including all anticipated dietary exposures and all other exposures for which there is reliable information.'' This includes exposure through drinking water and in residential settings, but does not include occupational exposure. Section 408(b)(2)(C) of FFDCA requires EPA to give special consideration to exposure of infants and children to the pesticide chemical residue in establishing a tolerance and to ''ensure that there is a reasonable certainty that no harm will result to infants and children from aggregate exposure to the pesticide chemical residue. . . .''

Consistent with FFDCA section 408(b)(2)(D), EPA has reviewed the available scientific data and other relevant information in support of this action. EPA has sufficient data to assess the hazards of and to make a determination on aggregate exposure, consistent with FFDCA section 408(b)(2).

In the **Federal Register** of September 24, 2014 (79 FR 56963) (FRL–9914–35), EPA established tolerances for residues of fluensulfone in or on cucurbit vegetable crop group 9 and fruiting vegetable crop group 8–10 at 0.50 parts per million (ppm). The information available to the Agency in support of the September 24, 2014 final rule showed no concentration of fluensulfone or the metabolite BSA in or on fruiting vegetable commodities and that separate tolerances for residues in or on processed tomato products were unnecessary. Therefore, EPA established a tolerance for residues of fluensulfone in or on fruiting vegetable crop group 8–10 at 0.50 ppm and determined that a separate tolerance for tomato, paste was not necessary.

Since the time of the September 24, 2014 final rule, EPA received a new tomato processing study that demonstrates a concentration of BSA residues in tomato paste (3.5X). Based on this concentration factor and the highest average field trial (HAFT) residues in tomato (0.29 ppm), the Agency determined that the fruiting vegetable crop group 8–10 tolerance at 0.5 ppm is insufficient to cover residues in tomato, paste and therefore a tolerance of 1.0 ppm in or on tomato, paste is necessary to cover residues of BSA.

The Agency assessed the use of fluensulfone in or on tomato, paste at the tolerance of 1.0 ppm and determined that there would be no resulting change in the risk estimates from the previous risk assessment for the chemical. Since the publication of the September 24, 2014 final rule, the toxicity profile of fluensulfone has not changed, and the risk assessments that supported the establishment of those tolerances published in the **Federal Register** remain valid. The dietary risk assessments for fluensulfone are based on residues of the parent compound only. Since residues of the parent did not concentrate in tomato paste, a new risk assessment is not necessary. Therefore, EPA relies upon those supporting risk assessments and the findings made in the September 24, 2014 **Federal Register** document, as well as the review of the additional tomato processing data in support of this rule. EPA concludes that there is a reasonable certainty that no harm will result to the general population, or to infants and children from aggregate exposure to fluensulfone residues.

For a detailed discussion of the aggregate risk assessments and determination of safety for the proposed tolerances, please refer to the September 24, 2014 **Federal Register** document and its supporting documents, available at *http://www.regulations.gov* in docket ID number EPA–HQ–OPP–2012–0593. Further information about EPA's determination that a separate tolerance should be established in or on tomato, paste may be found in the document, ''Fluensulfone—Revised Tolerance Recommendation for Tomato Paste.'' in docket ID number EPA–HQ–OPP–2015–0375.

IV. Other Considerations

A. Analytical Enforcement Methodology

Adequate enforcement methodology, a reverse-phase high performance liquid chromatography with dual mass spectrometry/mass spectrometry (HPLC–MS/MS), is available to enforce the tolerance expression.

The method may be requested from: Chief, Analytical Chemistry Branch, Environmental Science Center, 701 Mapes Rd., Ft. Meade, MD 20755–5350; telephone number: (410) 305–2905; email address: *residuemethods@epa.gov.*

B. International Residue Limits

In making its tolerance decisions, EPA seeks to harmonize U.S. tolerances with international standards whenever possible, consistent with U.S. food safety standards and agricultural practices. EPA considers the international maximum residue limits (MRLs) established by the Codex Alimentarius Commission (Codex), as required by FFDCA section 408(b)(4). The Codex Alimentarius is a joint United Nations Food and Agriculture Organization/World Health Organization food standards program, and it is recognized as an international food safety standards-setting organization in trade agreements to which the United States is a party. EPA may establish a tolerance that is different from a Codex MRL; however, FFDCA section 408(b)(4) requires that EPA explain the reasons for departing from the Codex level.

The Codex has not established a MRL for fluensulfone.

V. Conclusion

Therefore, tolerances are established for residues of fluensulfone, 3,4,4-trifluoro-but-3-ene-1-sulfonic acid, in or on tomato, paste at 1.0 ppm.

VI. Statutory and Executive Order Reviews

This action establishes a tolerance under FFDCA section 408(d) in response to a petition submitted to the Agency. The Office of Management and Budget (OMB) has exempted these types of actions from review under Executive Order 12866, entitled ''Regulatory Planning and Review'' (58 FR 51735, October 4, 1993). Because this action has been exempted from review under Executive Order 12866, this action is not subject to Executive Order 13211, entitled ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355, May 22, 2001) or Executive Order 13045, entitled ''Protection of Children from Environmental Health Risks and Safety Risks'' (62 FR 19885, April 23, 1997). This action does not contain any information collections subject to OMB approval under the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*), nor does it require any special considerations under Executive Order 12898, entitled ''Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations'' (59 FR 7629, February 16, 1994).

Since tolerances and exemptions that are established on the basis of a petition under FFDCA section 408(d), such as the tolerance in this final rule, do not require the issuance of a proposed rule, the requirements of the Regulatory Flexibility Act (RFA) (5 U.S.C. 601 *et seq.*), do not apply.

This action directly regulates growers, food processors, food handlers, and food retailers, not States or tribes, nor does this action alter the relationships or distribution of power and responsibilities established by Congress in the preemption provisions of FFDCA section 408(n)(4). As such, the Agency has determined that this action will not have a substantial direct effect on States or tribal governments, on the relationship between the national government and the States or tribal governments, or on the distribution of power and responsibilities among the various levels of government or between the Federal Government and Indian tribes. Thus, the Agency has determined that Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999) and Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000) do not apply to this action. In addition, this action does not impose any enforceable duty or contain any unfunded mandate as described under Title II of the Unfunded Mandates Reform Act (UMRA) (2 U.S.C. 1501 *et seq.*).

This action does not involve any technical standards that would require Agency consideration of voluntary consensus standards pursuant to section 12(d) of the National Technology Transfer and Advancement Act (NTTAA) (15 U.S.C. 272 note).

VII. Congressional Review Act

Pursuant to the Congressional Review Act (5 U.S.C. 801 *et seq.*), 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 United States prior to publication of the rule in the **Federal Register**. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 180

Environmental protection, Administrative practice and procedure, Agricultural commodities, Pesticides and pests, Reporting and recordkeeping requirements.

Dated: September 4, 2015.

Susan Lewis,

Director, Registration Division, Office of Pesticide Programs.

Therefore, 40 CFR chapter I is amended as follows:

PART 180—[AMENDED]

■ 1. The authority citation for part 180 continues to read as follows:

Authority: 21 U.S.C. 321(q), 346a and 371.

■ 2. In § 180.680, add alphabetically the following commodity to the table in paragraph (a) to read as follows:

§ 180.680 Fluensulfone; tolerances for residues.

(a) * * *

Commodity	Parts per million
Tomato, paste	1.0
* * * * * * *	

* * * * *

[FR Doc. 2015–23359 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 228

[EPA–R06–OW–2015–0121; FRL–9934–25–Region 6]

Ocean Dumping: Modification of Final Site Designation

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: The Environmental Protection Agency (EPA) today is modifying the use restrictions of the Galveston, TX Dredged Material Site, Freeport Harbor, TX, New Work (45 Foot Project), Freeport Harbor, TX, Maintenance (45 Foot Project), Matagorda Ship Channel, TX, Corpus Christi Ship Channel, TX, Port Mansfield, TX, Brazos Island Harbor, TX and Brazos Island Harbor (42-Foot Project), TX Ocean Dredged Material Disposal Sites (ODMDSs) located in the Gulf of Mexico offshore of Galveston, Freeport, Matagorda, Corpus Christi, Port Mansfield and Brownsville, Texas, respectively. These sites are EPA designated ocean dumping sites for the disposal of suitable dredged material. This action is being taken at the request of the United States Army Corps of Engineers Galveston District to allow disposal of suitable dredged material from the vicinity of the federal navigation channels to alleviate pressure on the capacity of their upland dredged material placement areas, when necessary.

DATES: This document is effective on October 19, 2015.

ADDRESSES: The EPA established a docket for this action under Docket No. EPA–R06–OW–2015–0121. All documents in the docket are listed on the *http://www.regulations.gov* Web site. Publicly available docket materials are available electronically through *http://www.regulations.gov*.

FOR FURTHER INFORMATION CONTACT: Jessica Franks, Ph.D., Marine and Coastal Section (6WQ–EC), Environmental Protection Agency, Region 6, 1445 Ross Avenue, Suite 1200, Dallas, Texas 75202–2733, telephone (214) 665–8335, fax number (214) 665–6689; email address *franks.jessica@epa.gov*.

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7. Executive Order 13045: Protection of Children from Environmental Health and Safety Risks
8. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use Compliance with Administrative Procedure Act
9. National Technology Transfer Advancement Act
10. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low Income Populations

A. Potentially Affected Persons

Persons potentially affected by this action include those who seek or might seek permits or approval by EPA to dispose of dredged material into ocean waters pursuant to the Marine Protection Research and Sanctuaries Act, 33 U.S.C. 1401 *et seq.* EPA's action would be relevant to persons, including organizations and government bodies seeking to dispose of dredged material in ocean waters offshore of Galveston, Freeport, Matagorda, Corpus Christi, Port Mansfield and Brownsville, Texas. Currently, the U.S. Army Corps of Engineers (Corps) and other persons with permits to use designated sites offshore of Galveston, Freeport, Matagorda, Corpus Christi, Port Mansfield, and Brownsville, Texas would be most impacted by this final action. Potentially affected categories and persons include:

TABLE 4—A SUMMARY OF PROPOSED DATA COLLECTION STANDARDS

Category	Examples of potentially regulated persons
Federal government	USACE Civil Works and O & M projects; other Federal agencies, including the Department of Defense.
Industry and general public	Port authorities, marinas and harbors, shipyards and marine repair facilities, berth owners
State, local and tribal governments.	Governments owning and/or responsible for ports, harbors, and/or berths, Government agencies requiring disposal of dredged material associated with public works projects.

This table is not intended to be exhaustive, but rather provides a guide for readers regarding persons likely to be affected by this action. For any questions regarding the applicability of this action to a particular entity, please refer to the contact person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section.

B. Background

Section 102(c) of the Marine Protection, Research, and Sanctuaries Act (MPRSA) of 1972, as amended, 33 U.S.C. 1401 *et seq.,* gives the Administrator of EPA the authority to designate sites where ocean disposal may be permitted. On October 1, 1986, the Administrator delegated the authority to designate ocean disposal sites to the Regional Administrator of the Region in which the sites are located. These modifications are being made pursuant to that authority.

The EPA Ocean Dumping Regulations promulgated under MPRSA (40 CFR Chapter I, Subchapter H, Section 228.11) state that modifications in disposal site use which involve withdrawal of disposal sites from use or permanent changes in the total specified quantities or types of waste permitted to be discharged to a specific disposal site will be made by promulgation in this Part 228. This site modification of types of waste permitted to be discharged to a specific disposal site are being published as a final rulemaking in accordance with § 228.11(a) of the Ocean Dumping Regulations, which permits changes in the total specified quantities or types of waste permitted to be discharged to a specific disposal site based upon changed circumstances concerning use of the site.

C. Final Action

The modifications of the use restrictions on the Galveston, TX, Dredged Material Site, Freeport Harbor, TX, New Work (45 Foot Project), Freeport Harbor, TX, Maintenance (45 Foot Project), Matagorda Ship Channel, TX, Corpus Christi Ship Channel, TX, Port Mansfield, TX, Brazos Island Harbor, TX and Brazos Island Harbor (42-Foot Project), TX ODMDSs was requested by the U.S. Army Corps of Engineers Galveston District in a March 27, 2015 letter. The current wording within the 40 CFR 228.15 restricts the use of these ODMDS to only dredged material originating from specific federal channel reaches associated with each ODMDS. For Freeport Harbor, TX, New Work (45 Foot Project) ODMDS and the Brazos Island Harbor (42-Foot Project), the ODMDSs are restricted to receive only construction dredged material from channel improvement projects at Freeport and Brazos Island Harbor, respectively. Modeling shows that future disposal capacity is limited at the placement areas typically used by the Galveston District when ocean disposal is not an option. As a result of these limitations, there is a need to change the use restrictions placed on these ODMDSs to include suitable dredged material from the greater vicinities of the respective federal channels. The restriction modification will provide for sufficient future dredged material disposal capacity for material originating from dredging areas within each Federal channel and its vicinity.

D. Responses to Comments

The proposed rule was published in the **Federal Register** on June 18, 2015 (80 FR 34871), as docket number EPA–EPA–R06–OW–2015–0121. The comment period closed on August 3, 2015. The EPA received one letter on the proposed rule from the Department of Interior stating that they have no comment. As no comments were received, the EPA has no responses to comments for the proposed rule.

E. Administrative Review

1. Executive Order 12866

Under Executive Order 12866 (58 FR 51735, October 4, 1993) EPA must determine whether the regulatory action is 'significant,'' and therefore subject to office of Management and Budget (OMB) review and other requirements of the Executive Order. The Order defines ''significant regulatory action'' as one that is likely to lead to a rule that may:

(a) 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;

(b) Create a serious inconsistency or otherwise interfere with an action taken or planned by another agency;

(c) Materially alter the budgetary impact of entitlements, grants, user fees, or loan programs, or the rights and obligations of recipients thereof: or

(d) Raise novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

This Final rule should have minimal impact on State, local, or Tribal governments or communities. Consequently, EPA has determined that this Final rule is not a ''significant regulatory action'' under the terms of Executive Order 12866.

2. Paperwork Reduction Act

The Paperwork Reduction Act, 44 U.S.C. 3501 *et seq.,* is intended to minimize the reporting and recordkeeping burden on the regulated community, as well as to minimize the cost of Federal information collection and dissemination. In general, the Act requires that information requests and record-keeping requirements affecting ten or more non-Federal respondents be approved by OMB. Since the Final rule would not establish or modify any information or recordkeeping requirements, but only clarifies existing requirements, it is not subject to the provisions of the Paperwork Reduction Act.

3. Regulatory Flexibility Act, as Amended by the Small Business Regulatory Enforcement Fairness Act of 1996

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.

This Final rule will not impose any requirements on small entities. The modification of the Galveston, TX, Dredged Material Site, Freeport Harbor, TX, New Work (45 Foot Project), Freeport Harbor, TX, Maintenance (45 Foot Project), Matagorda Ship Channel, TX, Corpus Christi Ship Channel, TX, Port Mansfield, TX, Brazos Island Harbor, TX and Brazos Island Harbor (42-Foot Project), TX ODMDSs broadens the use of the sites providing additional options for dredged material placement in the Galveston, Freeport, Matagorda, Corpus Christi, Port Mansfield and Brownsville, Texas vicinities.

For these reasons, the Regional Administrator certifies, pursuant to section 605(b) of the RFA, that the Final rule will not have a significant economic impact on a substantial number of small entities.

4. Unfunded Mandates Reform Act

This final rule contains no Federal mandates under the provisions of Title II of the Unfunded Mandates Reform Act of 1995 (UMRA) of 1995 (Pub. L. 104–4) for State, local, or tribal governments or the private sector that may result in estimated costs of $100 million or more in any year. It imposes no new enforceable duty on any State, local or tribal governments or the private sector nor does it contain any regulatory requirements that might significantly or uniquely affect small government entities. Thus, the requirements of section 203 of the UMRA do not apply to this final rule.

5. Executive Order 13132: Federalism

Executive Order 13132, entitled ''Federalism'' (64 FR 43255, August 10, 1999), requires EPA to develop an accountable process to ensure meaningful and timely input by State and local officials in the development of regulatory *policies that have federalism implications.* ''*Policies that have federalism implications''* are defined in the Executive Order to include regulations that have ''substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government.''

This final rule does not have federalism implications. It will not have substantial direct effects on the States, on the relationship between the national government and the States, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132.

6. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

Executive Order 13175, entitled ''Consultation and Coordination with Indian Tribal Governments'' (65 FR 67249, November 9, 2000), requires EPA to develop an accountable process to ensure ''meaningful and timely input by Tribal officials in the development of regulatory policies that have Tribal implications.'' This Final rule does not have Tribal implications, as defined in Executive Order 13175.

7. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

This Executive Order (62 FR 19885, April 23, 1997) applies to any rule that: (1) Is determined to be ''economically significant'' as defined under Executive Order 12866, and (2) concerns an environmental health or safety risk that EPA has reason to believe may have a disproportionate effect on children. If the regulatory action meets both criteria, EPA must evaluate the environmental health or safety effects of the planned rule on children, and explain why the planned regulation is preferable to other potentially effective and reasonably feasible alternatives considered by EPA. This final rule is not subject to the Executive Order because it is not economically significant as defined in Executive Order 12866, and because EPA does not have reason to believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

8. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use Compliance With Administrative Procedure Act

This Final rule is not subject to Executive Order 13211, ''Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use'' (66 FR 28355 (May 22, 2001)) because it is not a significant regulatory action under Executive Order 12866.

9. National Technology Transfer Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (''NTTAA''), Public Law 104–113, 12(d) (15 U.S.C. 272 note) directs EPA to use voluntary consensus standards in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. This Final rule does not involve technical standards. Therefore, EPA is not considering the use of any voluntary consensus standards.

10. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low Income Populations

Executive Order 12898 (59 FR 7629) directs Federal agencies to determine whether the Final rule would have a disproportionate adverse impact on minority or low-income population groups within the project area. The Final rule would not significantly affect any low-income or minority population.

List of Subjects in 40 CFR Part 228

Environmental protection, Water pollution control.

Dated: September 9, 2015.

Ron Curry,

Regional Administrator, Region 6.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is amended as follows:

PART 228—CRITERIA FOR THE MANAGEMENT OF DISPOSAL SITES FOR OCEAN DUMPING

■ 1. The authority citation for part 228 continues to read as follows:

Authority: 33 U.S.C. 1412 and 1418.

■ 2. Section 228.15 is amended by revising paragraphs (j)(12)(vi), (j)(13)(vi), (j)(14)(vi), (j)(15)(vi), (j)(17)(vi), (j)(18)(vi), (j)(19)(vi), and (j)(20)(vi) to read as follows:

§ 228.15 Dumping sites designated on a final basis.

* * * * *

(j) * * *

(12) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Houston-Galveston, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(13) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Freeport, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(14) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Freeport, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(15) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Matagorda, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

* * * * *

(17) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Corpus Christi, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(18)* * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Port Mansfield, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(19)* * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Brownsville, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

(20) * * *

(vi) *Restrictions:* Disposal shall be limited to suitable dredged material from the greater Brownsville, Texas vicinity. Disposal shall comply with conditions set forth in the most recent approved Site Management and Monitoring Plan.

* * * * *

[FR Doc. 2015–23475 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

48 CFR Part 211

Describing Agency Needs

CFR Correction

In Title 48 of the Code of Federal Regulations, Chapter 2, Parts 200 to 299, revised as of October 1, 2014, on page 68, correct section 211.002–70 to read as follows:

211.002–70 Contract clause.

Use the clause at 252.211–7000, Acquisition Streamlining, in all solicitations and contracts for systems acquisition programs.

[FR Doc. 2015–23456 Filed 9–17–15; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

48 CFR Part 215

Contracting by Negotiation

CFR Correction

In Title 48 of the Code of Federal Regulations, Chapter 2, Parts 200 to 299, revised as of October 1, 2014, on page 101, in section 215.404–71–4, in paragraph (f), remove the following two sentences: ''These are the normal values and ranges. They apply to all situations.''

[FR Doc. 2015–23457 Filed 9–17–15; 8:45 am]

BILLING CODE 1505–01–D

DEPARTMENT OF DEFENSE

Defense Acquisition Regulations System

48 CFR Part 237

Service Contracting

CFR Correction

In Title 48 of the Code of Federal Regulations, Chapter 2, Parts 200 to 299, revised as of October 1, 2014, on page 296, in section 237.102–70, paragraph (d)(2) is reinstated to read as follows:

§ 237.102–70 Prohibition on contracting for firefighting or security-guard functions.

* * * * *

(d) * * *

* * * * *

(2) Follow the procedures at PGI 237.102–70(d) to ensure that the personnel limitations specified in paragraph (d)(1)(iv) of this subsection are not exceeded.

[FR Doc. 2015–23458 Filed 9–17–15; 8:45 am]

BILLING CODE 1505–01–P

Proposed Rules

Federal Register

Vol. 80, No. 181

Friday, September 18, 2015

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

7 CFR Part 959

[Doc. No. AMS–FV–15–0036; FV15–959–1 PR]

Onions Grown in South Texas; Increased Assessment Rate

AGENCY: Agricultural Marketing Service, USDA.

ACTION: Proposed rule.

SUMMARY: This proposed rule would implement a recommendation from the South Texas Onion Committee (Committee) to increase the assessment rate established for the 2015–16 and subsequent fiscal periods from $0.03 to $0.05 per 50-pound equivalent of onions handled under the marketing order (order). The Committee locally administers the order and is comprised of producers and handlers of onions operating within the area of production. Assessments upon onion handlers are used by the Committee to fund reasonable and necessary expenses of the program. The fiscal period begins August 1 and ends July 31. The assessment rate would remain in effect indefinitely unless modified, suspended, or terminated.

DATES: Comments must be received by October 19, 2015.

ADDRESSES: Interested persons are invited to submit written comments concerning this proposed rule. Comments must be sent to the Docket Clerk, Marketing Order and Agreement Division, Fruit and Vegetable Program, AMS, USDA, 1400 Independence Avenue SW., STOP 0237, Washington, DC 20250–0237; Fax: (202) 720–8938; or Internet: *http://www.regulations.gov.* Comments should reference the document number and the date and page number of this issue of the **Federal Register** and will be available for public inspection in the Office of the Docket Clerk during regular business hours, or can be viewed at: *http://www.regulations.gov.* All comments submitted in response to this proposed rule will be included in the record and will be made available to the public. Please be advised that the identity of the individuals or entities submitting the comments will be made public on the internet at the address provided above.

FOR FURTHER INFORMATION CONTACT: Doris Jamieson, Marketing Specialist or Christian D. Nissen, Regional Director, Southeast Marketing Field Office, Marketing Order and Agreement Division, Fruit and Vegetable Program, AMS, USDA; Telephone: (863) 324–3375, Fax: (863) 291–8614, or Email: *Doris.Jamieson@ams.usda.gov* or *Christian.Nissen@ams.usda.gov.*

Small businesses may request information on complying with this regulation by contacting Jeffrey Smutny, Marketing Order and Agreement Division, Fruit and Vegetable Program, AMS, USDA, 1400 Independence Avenue SW., STOP 0237, Washington, DC 20250–0237; Telephone: (202) 720–2491, Fax: (202) 720–8938, or Email: *Jeffrey.Smutny@ams.usda.gov.*

SUPPLEMENTARY INFORMATION: This proposed rule is issued under Marketing Order No. 959, as amended (7 CFR part 959), regulating the handling of onions grown in South Texas, hereinafter referred to as the ''order.'' The order is effective under the Agricultural Marketing Agreement Act of 1937, as amended (7 U.S.C. 601–674), hereinafter referred to as the ''Act.''

The Department of Agriculture (USDA) is issuing this proposed rule in conformance with Executive Orders 12866, 13563, and 13175.

This proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. Under the marketing order now in effect, South Texas onion handlers are subject to assessments. Funds to administer the order are derived from such assessments. It is intended that the assessment rate as proposed herein would be applicable to all assessable onions beginning on August 1, 2015, and continue until amended, suspended, or terminated.

The Act provides that administrative proceedings must be exhausted before parties may file suit in court. Under section 608c(15)(A) of the Act, any handler subject to an order may file with USDA a petition stating that the order, any provision of the order, or any obligation imposed in connection with the order is not in accordance with law and request a modification of the order or to be exempted therefrom. Such handler is afforded the opportunity for a hearing on the petition. After the hearing, USDA would rule on the petition. The Act provides that the district court of the United States in any district in which the handler is an inhabitant, or has his or her principal place of business, has jurisdiction to review USDA's ruling on the petition, provided an action is filed not later than 20 days after the date of the entry of the ruling.

This proposed rule would increase the assessment rate established for the Committee for the 2015–16 and subsequent fiscal periods from $0.03 to $0.05 per 50-pound equivalent of onions.

The South Texas onion marketing order provides authority for the Committee, with the approval of USDA, to formulate an annual budget of expenses and collect assessments from handlers to administer the program. The members of the Committee are producers and handlers of South Texas onions. They are familiar with the Committee's needs and with the costs for goods and services in their local area and are thus in a position to formulate an appropriate budget and assessment rate. The assessment rate is formulated and discussed in a public meeting. Thus, all directly affected persons have an opportunity to participate and provide input.

For the 2012–13 and subsequent fiscal periods, the Committee recommended, and USDA approved, an assessment rate that would continue in effect from fiscal period to fiscal period unless modified, suspended, or terminated by USDA upon recommendation and information submitted by the Committee or other information available to USDA.

The Committee met on June 25, 2015, and unanimously recommended 2015–16 expenditures of $149,807 and an assessment rate of $0.05 per 50-pound equivalent of onions. Budgeted expenditures for 2014–15 were the same. The assessment rate of $0.05 is $0.02 higher than the rate currently in effect. With the 2015–16 crop estimated to be four million 50-pound equivalents, one million less than last year's estimate, the current assessment rate would be insufficient to cover the Committee's anticipated expenditures.

Further, due to a crop failure during the 2014–15 season, the Committee has depleted its reserve funds. With the Committee's recommended $0.02 increase, assessment income should be approximately $200,000. This would provide sufficient funds to cover anticipated 2015–16 expenses and add funds to the Committee's authorized reserve.

The major expenditures recommended by the Committee for the 2015–16 year include $50,000 for compliance, $37,050 for administrative, and $32,942 for management. Budgeted expenses for these items were the same in 2014–15.

The assessment rate recommended by the Committee was derived by considering anticipated expenses, expected shipments of South Texas onions, and the level of funds in reserve. As mentioned earlier, onion shipments for the year are estimated at four million 50-pound equivalents which should provide $200,000 in assessment income. Income derived from handler assessments at the proposed rate, along with interest income, would be adequate to cover budgeted expenses. Funds in the reserve (currently $23,906) would be kept within the maximum permitted by the order (approximately two fiscal periods' expenses as authorized in § 959.43).

The proposed assessment rate would continue in effect indefinitely unless modified, suspended, or terminated by USDA upon recommendation and information submitted by the Committee or other available information.

Although this assessment rate would be in effect for an indefinite period, the Committee would continue to meet prior to or during each fiscal period to recommend a budget of expenses and consider recommendations for modification of the assessment rate. The dates and times of Committee meetings are available from the Committee or USDA. Committee meetings are open to the public and interested persons may express their views at these meetings. USDA would evaluate Committee recommendations and other available information to determine whether modification of the assessment rate is needed. Further rulemaking would be undertaken as necessary. The Committee's 2015–16 budget and those for subsequent fiscal periods would be reviewed and, as appropriate, approved by USDA.

Initial Regulatory Flexibility Analysis

Pursuant to requirements set forth in the Regulatory Flexibility Act (RFA) (5 U.S.C. 601–612), the Agricultural Marketing Service (AMS) has considered the economic impact of this proposed rule on small entities. Accordingly, AMS has prepared this initial regulatory flexibility analysis.

The purpose of the RFA is to fit regulatory actions to the scale of businesses subject to such actions in order that small businesses will not be unduly or disproportionately burdened. Marketing orders issued pursuant to the Act, and the rules issued thereunder, are unique in that they are brought about through group action of essentially small entities acting on their own behalf.

There are approximately 60 producers of onions in the production area and approximately 20 handlers subject to regulation under the marketing order. Small agricultural producers are defined by the Small Business Administration (SBA) as those having annual receipts less than $750,000, and small agricultural service firms are defined as those whose annual receipts are less than $7,000,000 (13 CFR 121.201).

According to Committee data and information from the National Agricultural Statistical Service (NASS), the average price paid for South Texas onions during the 2013–2014 season was around $12.00 per 50-pound equivalents and total shipments were approximately 4.4 million 50-pound equivalents. Based on this information and data on acreage and yield, the majority of South Texas onion producers would have annual receipts of less than $750,000. In addition, based on available information, more than 50 percent of South Texas onion handlers could be considered small business under SBA's definition. Thus, the majority of South Texas onion producers and handlers may be classified as small entities.

This proposal would increase the assessment rate established for the Committee and collected from handlers for the 2015–16 and subsequent fiscal periods from $0.03 to $0.05 per 50-pound equivalent of Texas onions. The Committee unanimously recommended 2015–16 expenditures of $149,807 and an assessment rate of $0.05 per 50-pound equivalent. The proposed assessment rate of $0.05 is $0.02 higher than the 2012–13 rate. The quantity of assessable onions for the 2015–16 fiscal period is estimated at four million 50-pound equivalents. Thus, the $0.05 rate should provide $200,000 in assessment income and be adequate to meet this year's expenses.

The major expenditures recommended by the Committee for the 2015–16 fiscal period include $50,000 for compliance, $37,050 for administrative, and $32,942 for management. Budgeted expenses for these items were the same in 2014–15.

With the 2015–16 crop estimated to be four million 50-pound equivalents, one million less than last year's estimate, the current assessment rate would be insufficient to cover the Committee's anticipated expenditures. Further, due to a crop failure during the 2014–15 season, the Committee has depleted its reserve funds. The Committee recommended the $0.02 increase to provide sufficient funds to cover anticipated 2015–16 expenses and add funds to the Committee's authorized reserve.

Prior to arriving at this budget and assessment rate, the Committee considered information from various sources, such as the Committee's Budget and Personnel Committee. Alternative expenditure levels were discussed by this group, based upon the relative value of various activities to the South Texas onion industry. The Committee ultimately determined that 2015–16 expenditures of $149,807 were appropriate, and the recommended assessment rate, along with interest income, would generate sufficient revenue to meet its expenses.

A review of historical information and preliminary information pertaining to the upcoming season indicates that the grower price for the 2015–16 season should average around $9.55 per 50-pound equivalent of onions. Therefore, the estimated assessment revenue for the 2015–16 fiscal period as a percentage of total grower revenue would be approximately .52 percent for the season.

This action would increase the assessment obligation imposed on handlers. While assessments impose some additional costs on handlers, the costs are minimal and uniform on all handlers. Additionally, these costs would be offset by the benefits derived by the operation of the marketing order. In addition, the Committee's meeting was widely publicized throughout the South Texas onion industry and all interested persons were invited to attend the meeting and participate in Committee deliberations on all issues. Like all Committee meetings, the June 25, 2015, meeting was a public meeting and all entities, both large and small, were able to express views on this issue. Finally, interested persons are invited to submit comments on this proposed rule, including the regulatory and informational impacts of this action on small businesses.

In accordance with the Paperwork Reduction Act of 1995, (44 U.S.C. Chapter 35), the order's information collection requirements have been previously approved by the Office of Management and Budget (OMB) and assigned OMB No. 0581–0178 (Vegetable and Specialty Crops). No changes in those requirements are necessary as a result of this proposed action. Should any changes become necessary, they would be submitted to OMB for approval.

This proposed rule would impose no additional reporting or recordkeeping requirements on either small or large South Texas onion handlers. As with all Federal marketing order programs, reports and forms are periodically reviewed to reduce information requirements and duplication by industry and public sector agencies.

AMS is committed to complying with the E-Government Act, to promote the use of the Internet and other information technologies to provide increased opportunities for citizen access to Government information and services, and for other purposes.

USDA has not identified any relevant Federal rules that duplicate, overlap, or conflict with this action.

A small business guide on complying with fruit, vegetable, and specialty crop marketing agreements and orders may be viewed at: *http://www.ams.usda.gov/MarketingOrdersSmallBusinessGuide.* Any questions about the compliance guide should be sent to Jeffrey Smutny at the previously-mentioned address in the **FOR FURTHER INFORMATION CONTACT** section.

A 30-day comment period is provided to allow interested persons to respond to this proposed rule. Thirty days is deemed appropriate because: (1) The 2015–16 fiscal period begins on August 1, 2015, and the marketing order requires that the rate of assessment for each fiscal period apply to all assessable onions handled during such fiscal period; (2) the Committee needs to have sufficient funds to pay its expenses which are incurred on a continuous basis; and (3) handlers are aware of this action which was unanimously recommended by the Committee at a public meeting and is similar to other assessment rate actions issued in past years.

List of Subjects in 7 CFR Part 959

Marketing agreements, Onions, Reporting and recordkeeping requirements.

For the reasons set forth in the preamble, 7 CFR part 959 is proposed to be amended as follows:

PART 959—ONIONS GROWN IN SOUTH TEXAS

■ 1. The authority citation for 7 CFR part 959 continues to read as follows:

Authority: 7 U.S.C. 601–674.

■ 2. Section 959.237 is revised to read as follows:

§ 959.237 Assessment rate.

On and after August 1, 2015, an assessment rate of $0.05 per 50-pound equivalent is established for South Texas onions.

Dated: September 10, 2015.

Rex A. Barnes,

Associate Administrator, Agricultural Marketing Service.

[FR Doc. 2015–23436 Filed 9–17–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

9 CFR Part 327

[Docket No. FSIS–2012–0028]

RIN 0583–AD51

Eligibility of Namibia To Export Meat Products to the United States

AGENCY: Food Safety and Inspection Service, USDA.

ACTION: Proposed rule.

SUMMARY: The Food Safety and Inspection Service (FSIS) is proposing to add Namibia to the list of countries whose meat inspection system is equivalent to the system that the United States has established under the Federal Meat Inspect Act (FMIA) and its implementing regulations. FSIS's review of Namibia's laws, regulations, and inspection implementation show this to be the case.

At this time, because Namibia advised FSIS that it intends to export only boneless (not ground) raw beef products, such as primal cuts, chuck, blade, and beef trimmings to the United States, FSIS has only assessed Namibia's inspection system with respect to beef. Thus, should this rule become final, Namibia would need to submit additional information for FSIS to review before FSIS would allow Namibia to export product from other types of livestock to the U.S. All products that Namibia exports to the U.S. will be subject to re-inspection at United States ports of entry by FSIS inspectors.

DATES: Comments must be received on or before November 17, 2015.

ADDRESSES: FSIS invites interested persons to submit comments on this notice. Comments may be submitted by one of the following methods:

- *Federal eRulemaking Portal:* This Web site provides the ability to type short comments directly into the comment field or attach a file for lengthier comments. Go to *http://www.regulations.gov.* Follow the on-line instructions at that site for submitting comments.
- *Mail, including CD–ROMs, etc.:* Send to Docket Clerk, U.S. Department of Agriculture, Food Safety and Inspection Service, Patriots Plaza 3, 1400 Independence Avenue SW., Mailstop 3782, Room 8–163A, Washington, DC 20250–3700.
- *Hand- or courier-delivered submittals:* Deliver to Patriots Plaza 3, 355 E Street SW., Room 8–163A, Washington, DC 20250–3700.

Instructions: All items submitted by mail or electronic mail must include the Agency name and docket number FSIS–2012–0028. Comments received in response to this docket will be made available for public inspection and posted without change, including any personal information, to *http://www.regulations.gov.*

Docket: For access to background documents or comments received, go to the FSIS Docket Room at Patriots Plaza 3, 355 E Street SW., Room 8–164, Washington, DC 20250–3700 between 8:00 a.m. and 4:30 p.m., Monday through Friday.

FOR FURTHER INFORMATION CONTACT: Dr. Daniel Engeljohn, Assistant Administrator, Office of Policy and Program Development; Telephone: (202) 205–0495.

SUPPLEMENTARY INFORMATION:

Background

FSIS is proposing to amend its meat products inspection regulations to add Namibia to the list of countries eligible to export meat products to the United States (9 CFR 327.2(b)). Namibia is not currently listed as eligible to export such products to the United States.

Statutory Basis for Proposed Action

Under the FMIA and the regulations that implement it, meat and meat products imported into the United States must be produced under standards for safety, wholesomeness, and labeling accuracy that are equivalent to those of the United States (21 U.S.C. 620). The FMIA also requires that the livestock from which such imports are produced be slaughtered and handled in connection with slaughter in a manner that is consistent with the Humane Methods of Slaughter Act (7 U.S.C. 1901–1906). Section 327.2 of Title 9 of the Code of Federal Regulations (CFR) sets out the procedures by which foreign countries may become eligible to export meat and meat products to the United States.

Paragraph 327.2(a) of 9 CFR requires that a foreign country's meat inspection system provide standards equivalent to those of the United States and provide legal authority for the inspection system and its implementing regulations that is equivalent to that of the United States. Specifically, a country's legal authority and regulations must impose requirements equivalent to those of the United States with respect to: (1) Ante-mortem inspection, humane methods of slaughter and handling, and post-mortem inspection by, or under the direct supervision of, a veterinarian; (2) official controls by the national government over establishment construction, facilities, and equipment; (3) direct and continuous official supervision of slaughtering and preparation of product by inspectors to ensure that product is not adulterated or misbranded; (4) complete separation of establishments certified to export from those not certified; (5) maintenance of a single standard of inspection and sanitation throughout certified establishments; (6) requirements for sanitation and for sanitary handling of product at establishments certified to export; (7) official controls over condemned product; (8) a Hazard Analysis and Critical Control Point (HACCP) system; and (9) any other requirements found in the FMIA and its implementing regulations (9 CFR 327.2(a)(2)(ii)).

The country's inspection system must also impose requirements equivalent to those of the United States with respect to: (1) Organizational structure and staffing to ensure uniform enforcement of the requisite laws and regulations in all certified establishments; (2) national government control and supervision over the official activities of employees or licensees; (3) qualified inspectors; (4) enforcement and certification authority; (5) administrative and technical support; (6) inspection, sanitation, quality, species verification, and residue standards; and (7) any other inspection requirements (9 CFR 327.2(a)(2)(i)).

A foreign country's inspection system must be evaluated by FSIS before eligibility to export meat and meat products to the United States can be granted. This evaluation consists of two processes: A document review and an on-site review. The document review is an evaluation of the laws, regulations, and other written materials used by the country to effect its inspection program. FSIS requests that countries provide information about their inspection systems through its self-reporting tool (SRT). The SRT is a standardized questionnaire that FSIS provides to foreign governments to gather information that characterizes foreign inspection systems. Through the SRT, FSIS collects information on practices and procedures in six areas, known as equivalence components: (1) Government Oversight, (2) Statutory Authority and Food Safety Regulations, (3) Sanitation, (4) HACCP Systems, (5) Chemical Residue Testing Programs, and (6) Microbiological Testing Programs. FSIS evaluates the information submitted to verify that the critical points in the six equivalence components are addressed satisfactorily with respect to standards, activities, resources, and enforcement. If the document review is satisfactory, an onsite review is scheduled using a multidisciplinary team to evaluate all aspects of the country's inspection program. This comprehensive process is described more fully on the FSIS Web site at: *http://www.fsis.usda.gov/wps/portal/fsis/topics/international-affairs/importing-products/equivalence/equivalence-process-overview.*

The FMIA and implementing regulations require that foreign countries be listed in the CFR as eligible to export meat and meat products to the United States. FSIS must engage in rulemaking to list a country as eligible. Countries found eligible to export meat or meat products to the United States are listed in the meat inspection regulations at 9 CFR 327.2(b). Once listed, the government of an eligible country must certify to FSIS that establishments that wish to export meat products to the United States are operating under requirements equivalent to those of the United States (9 CFR 327.2(a)(3)). Countries must renew certifications of establishments annually (9 CFR 327.2(a)(3)).

Section 20 of the FMIA (21 U.S.C. 620) prohibits the importation into the United States of adulterated or misbranded carcasses, parts of carcasses, meat, or meat products of amenable species that are capable of use as human food. To verify that products imported into the United States are not adulterated or misbranded, FSIS reinspects and randomly samples those products at ports of entry, before they enter U.S. commerce.

Evaluation of the Namibian Meat Inspection System

In 2002 and again in 2005, the government of Namibia requested approval to export meat (beef) products to the United States. Namibia stated that, if approved, its immediate intent was to export boneless (not ground) raw beef products such as primal cuts, chuck, blade, and beef trimmings to the United States.

In 2006, FSIS conducted a document review of Namibia's meat (slaughter and processing) inspection system to determine whether that system is equivalent to the United States' meat inspection system. FSIS concluded, on the basis of that review, that Namibia's laws, regulations, control programs, and procedures were sufficient to achieve the level of public health protection required by FSIS.

Accordingly, FSIS proceeded with an on-site audit of Namibia's meat inspection system from September 25 to October 11, 2006, to verify whether Namibia's central competent authority (CCA) in charge of food inspection effectively implemented a meat inspection system equivalent to that of the United States. FSIS concluded that Namibia's meat inspection system did not meet the equivalence components for government oversight, statutory authority and food safety regulations, sanitation, HACCP, and chemical residue and microbiological testing programs. For example, FSIS found that the CCA did not have adequate administrative controls over the inspection system and lacked a training program to maintain the competency of the inspection personnel and laboratory analysts. Namibia did not provide direct and continuous inspection by the assigned government inspectors. Additionally, the sanitation programs at the establishments visited by the audit team lacked measures to prevent recurring deficiencies that could result in direct product contamination or adulteration, and inspectors did not identify the problems.

Following the 2006 on-site audit, Namibia provided a corrective action plan that addressed FSIS's findings. Namibia also implemented comprehensive inspection training programs on requirements consistent with FSIS requirements for all its inspection and laboratory personnel.

From September 2 to 9, 2009, FSIS conducted a follow-up on-site audit to determine whether the outstanding issues identified during the previous on-site audit had been resolved. The 2009 audit identified new systemic deficiencies within the equivalence components for government oversight, sanitation, HACCP, chemical residue, and microbiological testing programs. Specifically, the 2009 audit found that Namibia did not have a plan to continuously analyze and implement staffing requirements in order to provide relief staff assignments during planned and unplanned field inspection personnel absences. In addition, Namibia did not effectively require that establishments maintain sanitation programs to prevent insanitary conditions and product contamination. Namibia also did not provide effective verification to ensure HACCP plans were effectively implemented and did not provide adequate control over laboratory quality systems.

Following the 2009 on-site audit, Namibia again provided a comprehensive corrective action plan that addressed the findings identified. FSIS reviewed the corrective action plan and concluded that Namibia had satisfactorily addressed all the 2009 audit findings. In addition, FSIS concluded that Namibia's corrective action plan satisfactorily addressed all the previous 2006 audit findings.

In 2013, FSIS conducted an initial equivalence follow-up on-site audit of Namibia's meat inspection system and verified that Namibia had satisfactorily implemented the corrective action plans proffered in response to the 2009 on-site audit. In 2013, the FSIS audit identified new findings within the equivalence components of government oversight, statutory authority and food safety regulations, sanitation, and chemical residue testing programs. The audit found that although the CCA had implemented all corrective action plans related to government oversight, it was unable to provide any record to demonstrate that the inspection personnel at the local establishments were properly implementing and documenting inspection procedures. Additionally, inspection personnel were including non-compliance findings on the Inspection Verification Activities Sheet instead of using a separate non-compliance record (NR) form to document non-compliance findings. Regarding statutory authority and food safety regulations, Namibia had implemented all related corrective action plans but could not demonstrate that it had adequate records to verify that establishments met Specified Risk Materials (SRM) requirements, to enforce SRM requirements, and to prevent potential SRM contamination from cattle 30 months of age or older. The CCA also had not effectively implemented its verification procedures for sanitation performance standards and was unable to demonstrate how it assessed its residue plan results. Namibia's National Residue Program did not have sampling plan procedures or strategies for dealing with residue violators.

In response to the 2013 audit findings, Namibia implemented immediate corrective actions and submitted another corrective action plan that addressed the findings identified during the audit of its food safety system. FSIS reviewed Namibia's corrective action plan and concluded that Namibia had satisfactorily addressed 2013 audit findings. FSIS conducted another audit in 2014 to verify that Namibia had effectively implemented those corrective actions.

On the basis of the 2014 follow-up on-site audit, FSIS has concluded that Namibia has fully implemented the corrective action plan that it had submitted in response to the 2013 audit. FSIS did not find any significant problems during the audit. Furthermore, through the audit, FSIS found that Namibia has implemented a sampling and testing program for Shiga toxin-producing *Escherichia coli* (STEC) that is equivalent to FSIS's program. Therefore, FSIS has determined that the CCA has adequately addressed all previous audit findings and met FSIS equivalence criteria related to all six components.

In summary, FSIS has completed the document review, on-site audits, and verification of corrective actions as part of the equivalence process, and all outstanding issues have been resolved. FSIS has determined that, as implemented, Namibia's inspection system (slaughter and processing) with respect to beef is equivalent to the United States' meat inspection system. The final 2009, 2013, and 2014 audit reports on Namibia's meat inspection system (slaughter and processing) can all be found on the FSIS Web site at: *http://www.fsis.usda.gov/wps/portal/fsis/topics/international-affairs/importing-products/eligible-countries-products-foreign-establishments/foreign-audit-reports.*

Should this rule become final, Namibia will be eligible to export to the U.S. boneless (not ground) beef raw products such as primal cuts, chucks, blade, and beef trimmings. The government of Namibia will need to certify to FSIS that those establishments that wish to export beef or beef products to the United States are operating in accordance with requirements equivalent to those of the United States. FSIS will verify that the establishments certified by Namibia's government meet the United States requirements through periodic and regularly scheduled audits of Namibia's meat inspection system.

If this proposed rule is adopted, the beef products that Namibia exports to the United States will be subject to re-inspection at the U.S. ports-of-entry for, but not limited to, transportation damage, product and container defects, labeling, proper certification, general condition, and accurate count. Moreover, even though a foreign country may be listed in FSIS regulations as eligible to export to the United States, the exporting country's products must also comply with all other applicable requirements of the United States. These requirements include restrictions under 9 CFR part 94 of APHIS' regulations, which also regulate the export of meat products from foreign countries to the United States.

In the future, if Namibia wants to export other meat products to the U.S. (*e.g.,* pork products), it will need to notify FSIS and submit information about its requirements and inspection program for these products. FSIS would then review the information and determine whether the Agency needs to audit the operations in Namibia producing these products to determine whether the requirements and inspection program for these products is equivalent to those in the U.S. Namibia would not be allowed to export additional products to the U.S. until FSIS determines that the country's requirements and inspection program for the products are equivalent to FSIS's system.

In addition, FSIS will conduct other types of re-inspection activities, such as incubation of canned products to ensure product safety and taking product samples for laboratory analysis for the detections of drug and chemical residues, pathogens, species, and product composition. Products that pass re-inspection will be stamped with the official United States mark of inspection and allowed to enter United States commerce. If they do not meet United States requirements, they will be refused entry and within 45 days must be exported to the country of origin, destroyed, or converted to animal food (subject to approval of the U.S. Food and Drug Administration (FDA), depending on the violation. The import re-inspection activities can be found on the FSIS Web site at *http://www.fsis.usda.gov/wps/portal/fsis/topics/international-affairs/importing-products/phis-import-component/phis-implementation-letter-to-importers/ct_index.*

Executive Order 12866 and Regulatory Flexibility Act

This proposed rule has been designated a ''non-significant'' regulatory action under section 3(f) of

Executive Order (E.O.) 12866. Accordingly, the rule has not been reviewed by the Office of Management and Budget (OMB) under E.O. 12866.

Economic Impact Analysis for Namibia Export Equivalence

This proposed rule would add Namibia to the list of countries eligible to export meat products into the United States. The government of Namibia intends to certify only one Namibian establishment as eligible to export boneless raw beef products to the United States. Given this establishment's beef production capacity and the projected export volume, FSIS projects that this rule, if implemented, will not have an impact on the United States economy. The annual boneless beef production of this establishment averaged 21.4 million pounds from 2008 to 2014. The projected volume of export to the United States is about 1.9 million pounds in 2015, increasing to about 12.5 million pounds in 2019.[1] The average annual United States domestic beef production in 2012–2014 was 25.3 billion pounds, projected to be 24.2 billion pounds in 2015.[2] The total United States import of beef averages 2.47 billion pounds per year for 2012–2014, projected to be 2.91 billion pounds in 2015.[3] Therefore, the projected Namibia beef imports in 2015 would only be about 0.007% of total U.S. production and 0.07% of total U.S. imports. If Namibia achieves the projected export goal in 2019 and assuming that United States beef production and import volume stay about the same, the projected beef imports from Namibia would still only be about 0.05% of total U.S. production, and 0.5% of total U.S. imports.

Although Namibia indicates that, for now, it is seeking to export boneless beef products only, this would not preclude it from exporting other meat products in the future, provided that the products meet all FSIS and APHIS requirements and any additional requirements that FSIS might have in place with regard to the products. Therefore, the long-term economic impact could be larger than what we can assess right now.

[1] According to Namibia, this is the ''optimistic'' projection they wish to achieve. Market conditions will affect actual results.

[2] *http://www.ers.usda.gov/media/1823699/rmpfore_apr-2015_r.xls,* accessed on May 8, 2015; part of *Livestock, Dairy, & Poultry Outlook* at Economic Research Service, USDA.

[3] *Ibid.*

Effect on Small Entities

The FSIS Administrator has made a preliminary determination that this proposed rule will not have a significant impact on a substantial number of small entities, as defined by the Regulatory Flexibility Act (5 U.S.C. 601). As mentioned above, the expected trade volume is very small. Therefore, the proposed action should have no significant impact on small entities that produce beef products domestically.

Executive Order 12988, Civil Justice Reform

This proposed rule has been reviewed under Executive Order 12988, Civil Justice Reform. Under this rule: (1) All State and local laws and regulations that are inconsistent with this rule will be preempted; (2) no retroactive effect will be given to this rule; and (3) no administrative proceedings will be required before parties may file suit in court challenging this rule.

Paperwork Reduction Act

No new paperwork requirements are associated with this proposed rule. Foreign countries wanting to export meat and meat products to the United States are required to provide information to FSIS certifying that their inspection system provides standards equivalent to those of the United States, and that the legal authority for the system and their implementing regulations are equivalent to those of the United States. FSIS provided Namibia with questionnaires asking for detailed information about the country's inspection practices and procedures to assist that country in organizing its materials. This information collection was approved under OMB number 0583–0094. The proposed rule contains no other paperwork requirements.

E-Government Act

FSIS and USDA are committed to achieving the purposes of the E-Government Act (44 U.S.C. 3601, *et seq.*) by, among other things, promoting the use of the Internet and other information technologies and providing increased opportunities for citizen access to Government information and services, and for other purposes.

Additional Public Notification

FSIS will officially notify the World Trade Organization's Committee on Sanitary and Phytosanitary Measures (WTO/SPS Committee) in Geneva, Switzerland, of this proposal and will announce it on-line through the FSIS Web page located at: *http://www.fsis.usda.gov/regulations_&_policies/Proposed_Rules/index.asp.*

FSIS also will make copies of this publication available through the FSIS Constituent Update, which is used to provide information regarding FSIS policies, procedures, regulations, **Federal Register** notices, FSIS public meetings, and other types of information that could affect or would be of interest to our constituents and stakeholders. The Update is available on the FSIS Web page. Through the Web page, FSIS is able to provide information to a much broader, more diverse audience. In addition, FSIS offers an email subscription service which provides automatic and customized access to selected food safety news and information. This service is available at: *http://www.fsis.usda.gov/subscribe.* Options range from recalls to export information, regulations, directives, and notices. Customers can add or delete subscriptions themselves, and have the option to password protect their accounts.

USDA Non-Discrimination Statement

No agency, officer, or employee of the USDA shall, on the grounds of race, color, national origin, religion, sex, gender identity, sexual orientation, disability, age, marital status, family/parental status, income derived from a public assistance program, or political beliefs, exclude from participation in, deny the benefits of, or subject to discrimination any person in the United States under any program or activity conducted by the USDA.

How To File a Complaint of Discrimination

To file a complaint of discrimination, complete the USDA Program Discrimination Complaint Form, which may be accessed online at *http://www.ocio.usda.gov/sites/default/files/docs/2012/Complain_combined_6_8_12.pdf,* or write a letter signed by you or your authorized representative.

Send your completed complaint form or letter to USDA by mail, fax, or email: Mail: U.S. Department of Agriculture, Director, Office of Adjudication, 1400 Independence Avenue SW., Washington, DC 20250–9410. Fax: (202) 690–7442. Email: *program.intake@usda.gov.*

Persons with disabilities who require alternative means for communication (Braille, large print, audiotape, etc.), should contact USDA's TARGET Center at (202) 720–2600 (voice and TDD).

List of Subjects in 9 CFR Part 327

Imports, Meat Inspection.

For the reasons set out in the preamble, FSIS is proposing to amend 9 CFR part 327 as follows:

PART 327—IMPORTED PRODUCTS

■ 1. The authority citation for part 327 continues to read as follows:

Authority: 21 U.S.C. 601–695; 7 CFR 2.18, 2.53.

§ 327.2 [Amended]

■ 2. Amend § 327.2 by adding Namibia in alphabetical order to the list of countries in paragraph (b).

Done at Washington, DC, on September 14, 2015.

Alfred V. Almanza,

Acting Administrator.

[FR Doc. 2015–23455 Filed 9–17–15; 8:45 am]

BILLING CODE 3410–DM–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–3631; Directorate Identifier 2015–NM–060–AD]

RIN 2120–AA64

Airworthiness Directives; Airbus Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for certain Airbus Model A330–200 and –300 series airplanes; Model A330–200 Freighter series airplanes; and Model A340–200, –300, –500, and –600 series airplanes. This proposed AD was prompted by reports of chafed wiring at the upper left corner of the cockpit door. The affected wire bundle was not grounded on the cockpit door frame. This proposed AD would require modifying the cockpit door frame structure, installing bonding-leads to the upper cockpit door frame, and modifying the upper cockpit door plate cover. We are proposing this AD to prevent electrical shock injury to persons contacting the cockpit door.

DATES: We must receive comments on this proposed AD by November 2, 2015.

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: U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Airbus SAS, Airworthiness Office—EAL, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 45 80; email *airworthiness.A330-A340@airbus.com;* Internet *http://www.airbus.com.* You may view this referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3631; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Vladimir Ulyanov, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1138; fax 425–227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2015–3631; Directorate Identifier 2015–NM–060–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on 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 proposed AD.

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Union, has issued EASA Airworthiness Directive 2015–0037, dated March 2, 2015 (referred to after this as the Mandatory Continuing Airworthiness Information, or ''the MCAI''), to correct an unsafe condition for certain Airbus Model A330–200 and –300 series airplanes; Model A330–200 Freighter series airplanes; and Model A340–200, –300, –500, and –600 series airplanes. The MCAI states:

> An operator has reported chafed wiring at the upper left corner of the cockpit door. The investigation concluded that the affected wire bundle, which supplies a voltage of 115V [volt] AC [alternating current], was not grounded on the cockpit door frame as part of the design of A330 and A340 aeroplanes.
>
> This condition, if not corrected, could result in injury [electrical shock], in case any person gets in contact with the door frame.
>
> Prompted by these findings, Airbus issued SB [service bulletin] A330–25–3534, SB A340–25–4349 and SB A340–25–5212 to provide instructions to modify the electrical bonding of the cockpit door.
>
> For the reasons described above, this [EASA] AD requires modification of the cockpit door frame structure, installation of bonding-leads to the upper cockpit door frame and modification of the upper cockpit door plate cover.

You may examine the MCAI in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3631.

Related Service Information Under 1 CFR Part 51

Airbus has issued the following service information.

- Service Bulletin A330–25–3534, Revision 01, dated October 23, 2014. This service information describes procedures for modifying the cockpit door frame structure and installing bonding-leads to the upper cockpit door frame.
- Service Bulletin A340–25–4349, Revision 01, dated October 27, 2014. This service information describes procedures for modifying the cockpit door frame structure and installing bonding-leads to the upper cockpit door frame.
- Service Bulletin A340–25–5212, Revision 01, dated October 27, 2014. This service information describes procedures for modifying the cockpit door frame structure and installing

bonding-leads to the upper cockpit door frame.

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section of this NPRM.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with the State of Design Authority, we have been notified of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all pertinent information and determined an unsafe condition exists and is likely to exist or develop on other products of these same type designs.

Explanation of ''RC'' Procedures and Tests in Service Information

The FAA worked in conjunction with industry, under the Airworthiness Directive Implementation Aviation Rulemaking Committee (ARC), to enhance the AD system. One enhancement was a new process for annotating which procedures and tests in the service information are required for compliance with an AD. Differentiating these procedures and tests from other tasks in the service information is expected to improve an owner's/operator's understanding of crucial AD requirements and help provide consistent judgment in AD compliance. The procedures and tests identified as Required for Compliance (RC) in any service information have a direct effect on detecting, preventing, resolving, or eliminating an identified unsafe condition.

As specified in a NOTE under the Accomplishment Instructions of the specified service information, procedures and tests that are identified as RC in any service information must be done to comply with the proposed AD. However, procedures and tests that are not identified as RC are recommended. Those procedures and tests that are not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an alternative method of compliance (AMOC), provided the procedures and tests identified as RC can be done and the airplane can be put back in a serviceable condition. Any substitutions or changes to procedures or tests identified as RC will require approval of an AMOC.

Costs of Compliance

We estimate that this proposed AD affects 70 airplanes of U.S. registry.

We also estimate that it would take about 27 work-hours per product to comply with the basic requirements of this proposed AD. The average labor rate is $85 per work-hour. Required parts would cost about $2,620 per product. Based on these figures, we estimate the cost of this proposed AD on U.S. operators to be $344,050, or $4,915 per product.

According to the manufacturer, some of the costs of this proposed AD may be covered under warranty, thereby reducing the cost impact on affected individuals. We do not control warranty coverage for affected individuals. As a result, we have included all costs in our cost estimate.

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

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;

2. Is not a ''significant rule'' under the 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.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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):

Airbus: Docket No. FAA–2015–3631; Directorate Identifier 2015–NM–060–AD.

(a) Comments Due Date

We must receive comments by November 2, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to all the Airbus airplanes identified in paragraphs (c)(1), (c)(2), and (c)(3) of this AD, certificated in any category, except airplanes on which Airbus Modification 203066, Modification 203074, or Modification 203372 has been embodied in production.

(1) Model A330–201, –202, –203, –223, –223F, –243, –243F, –301, –302, –303, –321, –322, –323, –341, –342, and –343 airplanes; all manufacturer serial numbers (MSNs); if modified in-service as specified in Airbus Service Bulletin A330–25–3161, or in production with Airbus Modification 50014.

(2) Model A340–211, –212, –213, –311, –312, and –313 airplanes; all MSNs, if modified in-service as specified in Airbus Service Bulletin A340–25–4181, or in production with Airbus Modification 50014.

(3) Model A340–541 airplanes; and Model A340–642 airplanes; all MSNs.

(d) Subject

Air Transport Association (ATA) of America Code 25, Equipment/Furnishings.

(e) Reason

This AD was prompted by reports of chafed wiring at the upper left corner of the cockpit door. The affected wire bundle was not grounded on the cockpit door frame. We are issuing this AD to prevent electrical shock injury to persons contacting the cockpit door.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Door Modification and Installation

Within 24 months after the effective date of this AD, modify the cockpit door frame structure and install bonding-leads to the upper cockpit door frame, in accordance with the Accomplishment Instructions of the applicable service information identified in paragraphs (g)(1), (g)(2), and (g)(3) of this AD.

(1) Airbus Service Bulletin A330–25–3534, Revision 01, dated October 23, 2014. (2) Airbus Service Bulletin A340–25–4349, Revision 01, dated October 27, 2014. (3) Airbus Service Bulletin A340–25–5212, Revision 01, dated October 27, 2014.

(h) Cover Plate Modification of the Upper Flight Deck Door

Except for airplanes on which Airbus Modification 52869 or Modification 53292 has been embodied in production: Before or concurrently with accomplishing the modification required by paragraph (g) of this AD, modify the upper cockpit door plate cover, in accordance with the Accomplishment Instructions of the applicable service information identified in paragraphs (h)(1), (h)(2), and (h)(3) of this AD.

(1) Airbus Service Bulletin A330–25–3534, Revision 01, dated October 23, 2014. (2) Airbus Service Bulletin A340–25–4349, Revision 01, dated October 27, 2014. (3) Airbus Service Bulletin A340–25–5212, Revision 01, dated October 27, 2014.

(i) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager International Branch, ANM–116, Transport Airplane Directorate, 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 International Branch, send it to ATTN: Vladimir Ulyanov, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1138; fax 425–227–1149. Information may be emailed to: *9-ANM-116-AMOC-REQUESTS@faa.gov.* 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. The AMOC approval letter must specifically reference this AD.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain corrective actions from a manufacturer, the action must be accomplished using a method approved by the Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA; or the European Aviation Safety Agency (EASA); or Airbus's EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(3) *Required for Compliance (RC):* If any service information contains procedures or tests that are identified as RC, those procedures and tests must be done to comply with this AD; any procedures or tests that are not identified as RC are recommended. Those procedures and tests that are not identified as RC may be deviated from using accepted methods in accordance with the operator's maintenance or inspection program without obtaining approval of an AMOC, provided the procedures and tests identified as RC can be done and the airplane can be put back in a serviceable condition. Any substitutions or changes to procedures or tests identified as RC require approval of an AMOC.

(j) Related Information

(1) Refer to Mandatory Continuing Airworthiness Information (MCAI) EASA Airworthiness Directive 2015–0037, dated March 2, 2015, for related information. This MCAI may be found in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3631.

(2) For service information identified in this AD, contact Airbus SAS, Airworthiness Office—EAL, 1 Rond Point Maurice Bellonte, 31707 Blagnac Cedex, France; telephone +33 5 61 93 36 96; fax +33 5 61 93 45 80; email *airworthiness.A330–A340@airbus.com;* Internet *http://www.airbus.com.* You may view this service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on September 11, 2015.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2015–23409 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2014–0774; Directorate Identifier 2013–NM–154–AD]

RIN 2120–AA64

Airworthiness Directives; The Boeing Company Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Supplemental notice of proposed rulemaking (SNPRM); reopening of comment period.

SUMMARY: We are revising an earlier proposed airworthiness directive (AD) that proposed to supersede AD 2006–22–15 for all The Boeing Company Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747–400, 747–400D, 747–400F, 747SR, and 747SP series airplanes. AD 2006–22–15 requires repetitive inspections for cracking of certain panel webs and stiffeners of the nose wheel well (NWW), and corrective actions if necessary; and replacement of certain panels with new panels, which terminates the repetitive inspections. The notice of proposed rulemaking (NPRM) proposed to reduce a compliance time and add certain inspections and applicable repair. The NPRM was prompted by reports of fatigue cracking in the panel webs and stiffeners of the NWW found prior to the inspection threshold of AD 2006–22–15. This action revises the NPRM by specifying a repetitive inspection interval for a certain NWW area inspection. We are proposing this SNPRM to prevent fatigue cracking of the NWW side and top panels, which could result in a NWW depressurization event severe enough to reduce the structural integrity of the fuselage. Since these actions impose an additional burden over that proposed in the NPRM, we are reopening the comment period to allow the public the chance to comment on these proposed changes.

DATES: We must receive comments on this SNPRM by November 2, 2015.

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:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Boeing Commercial Airplanes, Attention: Data & Services Management, P. O. Box 3707, MC 2H–65, Seattle, WA 98124–2207; telephone 206–544–5000, extension 1; fax 206–766–5680; Internet *https://www.myboeingfleet.com.* You may view this referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221. It is also available on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2014–0774.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2014–0774; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket 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: Bill Ashforth, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle Aircraft Certification Office (ACO), 1601 Lind Avenue SW., Renton, WA 98057–3356; phone: 425–917–6432; fax: 425–917–6590; email: *Bill.Ashforth@faa.gov.*

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2014–0774; Directorate Identifier 2013–NM–154–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed 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 proposed AD.

Discussion

We issued an NPRM to amend 14 CFR part 39 to supersede AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006). AD 2006–22–15 applies to all Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747–400, 747–400D, 747–400F, 747SR, and 747SP series airplanes. The NPRM published in the **Federal Register** on November 17, 2014 (79 FR 68388). The NPRM was prompted by reports of fatigue cracking in the panel webs and stiffeners of the NWW found prior to the inspection threshold of AD 2006–22–15. The NPRM proposed to continue to require repetitive inspections for cracking of certain panel webs and stiffeners of the NWW, and corrective actions if necessary. The NPRM also proposed to continue to require replacing certain panels with new panels, which would terminate the repetitive inspections. The NPRM proposed to reduce a compliance time and add certain inspections and applicable repair.

Actions Since Previous NPRM (79 FR 68388, November 17, 2014) Was Issued

Since we issued the NPRM (79 FR 68388, November 17, 2014), we have determined that it is necessary to revise the NPRM by specifying a certain repetitive inspection interval for Area 2 for airplanes with less than 15,000 total flight cycles. This interval is not clearly indicated in table 1 of paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, and was not specifically stated in the NPRM.

Related Service Information Under 1 CFR Part 51

We reviewed the following Boeing service information. Refer to this service information for information on the procedures and compliance times.

- Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, which describes procedures for inspections for cracks of certain top and sidewall panel webs and stiffeners of the NWW; and repairs.
- Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013. This service bulletin describes procedures for replacement of the side and top panel webs and certain stiffeners of the NWW; an inspection for cracks in attaching structural elements that are common to the removed top panel and side panels; repetitive post-modification inspections for cracks in the top and side panel webs and stiffeners; and contacting Boeing for repairs.
- Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012. This service bulletin describes procedures for replacement of the side and top panel webs, support beams, and stiffeners of the NWW; an inspection for cracks of the attaching structural elements that are common to the removed top and side panels of the NWW; repetitive post-modification inspections for cracks in the top and side panel webs and stiffeners; and contacting Boeing for repairs.

This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section of this AD.

Comments

We gave the public the opportunity to comment on the NPRM (79 FR 68388, November 17, 2014). The following presents the comments received on the NPRM and the FAA's response to each comment.

Requests To Specify Repetitive Inspection Interval for Area 2

United Airlines (UAL) and United Parcel Service (UPS) requested that we specify the repetitive inspection interval for Area 2 for airplanes with less than 15,000 total flight cycles. The commenters point out that this is not clearly indicated in table 1 of paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, and was not specifically stated in the NPRM (79 FR 68388, November 17, 2014). The commenters stated that Boeing has issued a service bulletin information notice to inform operators that the repetitive inspection interval for Area 2 should be 1,000 flight cycles.

We agree with the commenters' requests to specify the repeat interval for Area 2. We have revised paragraph (g) of this SNPRM to specify this interval.

Request To Specify Repair Procedures

UAL asked whether paragraph (h)(3) of the proposed AD (79 FR 68388, November 17, 2014) should be revised to specify repair requirements for each area, instead of contacting the FAA or the Boeing Commercial Airplanes Organization Designation Authorization (ODA) for repair instructions for any cracking or damage found during the inspection specified in paragraph (g) of the proposed AD. UAL explained that Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, specifies repairing web cracks in Area 1 or 2 per the ''747 Structural Repair Manuals.''

We agree to provide clarification. The intent of paragraph (h)(3) of this SNPRM is to make sure that for those conditions for which Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, specifies that the operator is to contact Boeing for repair data, the operator would be required to use a repair method approved by the FAA or Boeing Commercial Airplanes ODA. We have not changed this SNPRM in this regard.

Request To Clarify Certain Compliance Times

UAL requested clarification of why the footnotes in table 2 of paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, reverted back to 6,000 flight cycles for Area 3 inspections for cracks of the sidewall panel and top panel stiffeners. UAL also asked why the 6,000-flight-cycle time is just for the first repeat inspection and then Area 3 has to be reinspected every 1,500 flight cycles thereafter.

We agree that clarification is necessary. Paragraph (f)(2) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), specifies the 6,000-flight-cycle and 1,500-flight-cycle inspection times. Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, states that inspections and corrective actions defined therein are an alternative method of compliance (AMOC) to the requirements of paragraphs (f), (g), (h), (i), and (j) of AD 2006–22–15. In order to be approved as an AMOC to certain requirements of AD 2006–22–15, Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, must state the compliance times required by AD 2006–22–15 to address the identified unsafe condition. We have not changed this SNPRM in this regard.

Request To Revise Certain Headers To Clarify Intent of Requirements

Boeing requested that we revise the heading of paragraph (g) of the proposed AD (79 FR 68388, November 17, 2014) to either change ''Repetitive Inspections'' to ''Initial and Repetitive Inspections'' or delete ''Repetitive.'' Boeing stated that paragraph (g) of the proposed AD contains both initial and repetitive inspections.

Boeing requested that we delete ''Repetitive'' from the headings of paragraphs (j) and (m) of the proposed AD (79 FR 68388, November 17, 2014). Boeing stated that paragraphs (j) and (m) of the proposed AD specify not only repetitive inspections, but also the initial post-modification inspections.

We agree that clarification is necessary. We do not consider that the term ''repetitive'' necessarily excludes the initial action. An action cannot be repeated without accomplishment of the initial action. Many existing ADs refer to ''repetitive'' actions, which we intend as including the initial action. In addition, changing ''Repetitive Inspections'' to simply ''Inspections'' could result in the misinterpretation that multiple different inspections are required. We have not changed this SNPRM regarding this issue.

Request To Clarify Inspection Location

Boeing requested that, at the end of paragraph (g)(3) of the proposed AD (79 FR 68388, November 17, 2014), we add ''of the NWW (specified as Area 1 and Area 2 in Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013)'' for the ultrasonic inspection.

We agree with the commenter's request. This revision will make the wording in paragraph (g)(3) of this proposed AD consistent with the wording of each of the areas specified in paragraphs (g)(1) and (g)(2) of this proposed AD. We have revised paragraph (g)(3) of this proposed AD accordingly.

Request To Add New AMOC Limitation

Boeing requested that we add a new paragraph (p)(6) to the NPRM (79 FR 68388, November 17, 2014), which would state that ''New provisions (inspection threshold and interval) in this AD must be complied with as given in this AD.'' Boeing stated that this statement will make it clear that prior AMOCs do not exempt the operators from compliance with new requirements added by this new proposed AD. Boeing also stated that the wording of ''corresponding provisions'' in paragraph (p)(4) of the proposed AD (79 FR 68388, November 17, 2014) might not be precise enough, when ADs get superseded and paragraphs change. Boeing explained that adding this statement will reduce the ambiguity of paragraphs (o) and (p) of the proposed AD.

We partially agree with the commenter's request. We have revised paragraph (p)(4) of this proposed AD to state that AMOC actions approved previously for AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), are approved as AMOCs for the corresponding actions of this AD. The compliance times in AMOCs approved previously for AD 2006–22–15 are not approved for the corresponding actions and compliance times in this AD. We have removed paragraph (p)(5) of this proposed AD as it is no longer necessary. We consider this language to be sufficiently clear. Adding the commenter's requested language would be redundant to the language specified in revised paragraph (p)(4) of this proposed AD.

Requests for Certain Editorial Changes

Boeing noted that paragraph (m) of the proposed AD (79 FR 68388, November 17, 2014) incorrectly referred to paragraphs ''(l)(1), (l)(2), and (l)(3).'' Boeing asked that we change these references to ''(m)(1), (m)(2), and (m)(3).''

Boeing requested that we correct the AD citation in paragraph (o)(1)(i) of the proposed AD (79 FR 68388, November 17, 2014). Boeing stated that the identified effective date of January 27, 2005, is for AD 2004–25–23, Amendment 39–13911 (69 FR 76839, December 23, 2004); not AD 2005–09–02, Amendment 39–14070 (70 FR 21141, April 25, 2005; corrected May 25, 2005, 70 FR 29940)); as stated in the NPRM.

Boeing requested that we correct the date of Boeing Service Bulletin 747–53A2465, Revision 4, from February 25, 2004, to February 24, 2005, in paragraph (o)(2) of the proposed AD (79 FR 68388, November 17, 2014).

UPS requested that we revise paragraph (p)(1) of the proposed AD (79 FR 68388, November 17, 2014) to correct the paragraph identifier for the contact person, which should be paragraph ''(q)(1).''

We agree with the requests and have revised this SNPRM accordingly.

FAA's Determination

We are proposing this SNPRM because we evaluated all the relevant information and determined the unsafe condition described previously is likely to exist or develop in other products of this same type design. Certain changes described above expand the scope of the NPRM (79 FR 68388, November 17, 2014). As a result, we have determined that it is necessary to reopen the comment period to provide additional opportunity for the public to comment on this SNPRM.

Proposed Requirements of This SNPRM

Although this proposed AD does not explicitly restate certain requirements of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), this proposed AD would retain all of the requirements of AD 2006–22–15.

The requirements specified in paragraphs (f), (g), (h), (i), (j), and (l) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), are referenced in Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, which, in turn, is referenced in paragraphs (g) and (h)(3) of this proposed AD.

The requirement specified in paragraph (n) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), is referenced in Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, which, in turn, is referenced in paragraph (i) of this proposed AD.

For Group 2 airplanes identified in Boeing Service Bulletin 747–53A2562, Revision 1, dated July 28, 2005, and certain airplanes not identified in Boeing Service Bulletin 747–53A2562, Revision 1, dated July 28, 2005, the requirement specified in paragraph (o) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), to accomplish a repair using a method approved by the FAA is now specified in paragraph (i) of this proposed AD. However, for these airplanes, one method of compliance for accomplishing the replacement is Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013. Therefore, we have referred to Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, in paragraph (i) of this proposed AD. Operators may still request an alternative method of compliance (AMOC) using the procedures provided in paragraph (p) of this AD.

For certain other airplanes not identified in Boeing Service Bulletin 747–53A2562, Revision 1, dated July 28, 2005, the requirement specified in paragraph (o) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), to accomplish a repair using a method approved by the FAA is now specified in paragraph (l) of this proposed AD. However, for these airplanes, one method of compliance for accomplishing the replacement is Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012. Therefore, we have referred to Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012, in paragraph (l) of this proposed AD. Operators may still request an AMOC using the procedures provided in paragraph (p) of this AD.

This proposed AD would require accomplishing the actions specified in the service information identified previously, except as discussed under ''Differences Between the Proposed AD and the Service Information.'' Refer to this service information for information on the procedures and compliance times.

The phrase ''related investigative actions'' is used in this proposed AD. ''Related investigative actions'' are follow-on actions that (1) are related to the primary actions, and (2) further investigate the nature of any condition found. Related investigative actions in an AD could include, for example, inspections.

The phrase ''corrective actions'' is used in this proposed AD. ''Corrective actions'' are actions that correct or address any condition found. Corrective actions in an AD could include, for example, repairs.

Differences Between the Proposed AD and the Service Information

For airplanes with fewer than 15,000 total flight cycles, Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, recommends, in part, accomplishing a detailed inspection before the accumulation of 13,000 total flight cycles. However, we have determined that the 13,000-total-flight-cycle compliance time is insufficient to address the identified unsafe condition soon enough to ensure an adequate level of safety for the affected fleet. Instead, we are proposing a compliance time of 10,000 total flight cycles. In developing an appropriate compliance time for this detailed inspection, we considered the degree of urgency associated with the subject unsafe condition, and the fact that we have received a report of a 13-inch crack adjacent to a 2-inch crack in the NWW right-hand side panel on an airplane with 11,428 total flight cycles. This difference has been coordinated with The Boeing Company.

Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013; Boeing Service Bulletin 747 53A2562, Revision 3, dated July 11, 2013; and Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012; specify to contact the manufacturer for instructions on how to repair certain conditions, but this proposed AD would require repairing those conditions in one of the following ways:

- In accordance with a method that we approve; or
- Using data that meet the certification basis of the airplane, and that have been approved by the Boeing Commercial Airplanes ODA whom we have authorized to make those findings.

Explanation of Compliance Time

The compliance time for the modification specified in paragraphs (i) and (l) of this proposed AD for addressing widespread fatigue damage (WFD) was established to ensure that discrepant structure is modified before WFD develops in airplanes. Standard inspection techniques cannot be relied on to detect WFD before it becomes a hazard to flight. We will not grant any extensions of the compliance time to complete any AD-mandated service bulletin related to WFD without extensive new data that would substantiate and clearly warrant such an extension.

Costs of Compliance

We estimate that this proposed AD affects 255 airplanes of U.S. registry.

We estimate the following costs to comply with this proposed AD:

ESTIMATED COSTS

Action	Labor cost	Parts cost	Cost per product	Cost on U.S. operators
Inspections [actions retained from AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006)].	119 work-hours × $85 per hour = $10,115 per inspection cycle.	$0	$10,115 per inspection cycle.	$2,579,325 per inspection cycle.
Modification [actions retained from AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006)].	Up to 1,346 work-hours × $85 per hour = $114,410.	Up to $144,248	Up to $258,658	Up to $65,957,790.
Post-modification Inspections [new proposed action].	119 work-hours × $85 per hour = $10,115 per inspection cycle.	$0	$10,115 per inspection cycle.	$2,579,325 per inspection cycle.

We have received no definitive data that would enable us to provide cost estimates for the on-condition actions specified in this proposed AD.

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

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

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

(2) Is not a ''significant rule'' under the 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.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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):

The Boeing Company: Docket No. FAA–2014–0774; Directorate Identifier 2013–NM–154–AD.

(a) Comments Due Date

We must receive comments by November 2, 2015.

(b) Affected ADs

This AD replaces AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006).

(c) Applicability

This AD applies to all Boeing Model 747–100, 747–100B, 747–100B SUD, 747–200B, 747–200C, 747–200F, 747–300, 747–400, 747–400D, 747–400F, 747SR, and 747SP series airplanes, certificated in any category.

(d) Subject

Air Transport Association (ATA) of America Code 53, Fuselage.

(e) Unsafe Condition

This AD was prompted by multiple reports of cracking in the nose wheel well (NWW) top panel and side panel webs and stiffeners caused by fatigue. We are issuing this AD to prevent fatigue cracking of the NWW side and top panels, which could result in a NWW depressurization event severe enough to reduce the structural integrity of the fuselage.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Repetitive Inspections and Corrective Actions With New Compliance Times

Except as specified in paragraphs (h)(1) and (h)(2) of this AD, at the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013: Do the actions specified in paragraphs (g)(1), (g)(2), and (g)(3) of this AD, and do all applicable related investigative and corrective actions; in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, except as specified in paragraph (h)(3) of this AD. Do all applicable related investigative and corrective actions before further flight. Repeat the inspections specified in paragraphs (g)(1), (g)(2), and (g)(3) of this AD thereafter at the applicable intervals specified in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013. The repetitive interval for the inspection of Area 2 specified in table 1 in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, is 1,000 flight cycles. In table 2 and table 3 in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, the date ''January 27, 2005'' is the effective date of AD 2004–25–23, Amendment 39–13911 (69 FR 76839, December 23, 2004); and the date ''May 10, 2005'' is the effective date of AD 2005–09–02, Amendment 39–14070 (70 FR 21141, April 25, 2005; corrected May 25, 2005 (70 FR 29940)).

(1) Do an external detailed inspection for cracks of the top and sidewall panel webs of the NWW (specified as Area 1 and Area 2 in Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013).

(2) Do internal detailed and surface high frequency eddy current (HFEC) inspections for cracks of the sidewall panel and top panel stiffeners of the NWW (specified as Area 3 in Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013).

(3) Do an external detailed and ultrasonic testing (UT) inspection for cracks of the top and sidewall panel webs of the NWW (specified as Area 1 and Area 2 in Boeing Service Bulletin 747 -53A2465, Revision 5, dated July 11, 2013).

(h) Exceptions to Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013

(1) Table 1 in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, applies to airplanes with less than 15,000 total flight cycles ''as of the Revision 5 date of this service bulletin.'' For this AD, however, table 1 applies to airplanes with the specified total flight cycles as of the effective date of this AD.

(2) Table 1 in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, specifies a compliance time of ''13,000 total flight-cycles,'' or ''within 1,000 flights cycles after the Revision 5 date of this service bulletin,'' whichever occurs later. This AD requires compliance before the accumulation of 10,000 total flight cycles or within 1,000 flight cycles after the effective date of this AD, whichever occurs later.

(3) If any cracking or damage is found during any inspection required by paragraph (g) of this AD, and Boeing Service Bulletin 747–53A2465, Revision 5, dated July 11, 2013, specifies to contact Boeing for appropriate action: Before further flight, repair the cracking or damage using a method approved in accordance with the procedures specified in paragraph (p) of this AD.

(i) NWW Modification

For airplanes identified in Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013: At the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, replace the left-side, right-side, and top panels of the NWW, as applicable, with new panels, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013. As of the effective date of this AD, concurrently with doing the replacement specified in Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, do a detailed inspection for any cracks or damage (including, but not limited to, dents and corrosion) in all attaching structural elements that are common to the removed top panel and side panels, as applicable, and do all applicable corrective actions, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013. If any crack or damage is found, before further flight, repair the cracking or damage using a method approved in accordance with the procedures specified in paragraph (p) of this AD. In paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, the date ''December 11, 2006,'' is the effective date of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006).

(j) Repetitive Post-Modification Inspections

For airplanes on which the replacement specified in paragraph (i) of this AD has been done: Except as required by paragraph (k) of this AD, at the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, do the actions specified in paragraphs (j)(1), (j)(2), and (j)(3) of this AD. If any crack is found: Before further flight, repair the cracking using a method approved in accordance with the procedures specified in paragraph (p) of this AD. Repeat the inspections specified in paragraphs (j)(1), (j)(2), and (j)(3) of this AD thereafter at the applicable intervals specified in paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013.

(1) Do an external detailed inspection for cracks in the side panel webs, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013.

(2) Do an internal detailed inspection and high frequency eddy current (HFEC) inspection for cracks in the top and side panel stiffeners, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013.

(3) Do an external detailed inspection for cracks in the top panel web, in accordance with the Accomplishment Instructions of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013.

(k) Exception to Boeing Service Bulletin 747–53A2562, Revision 3, Dated July 11, 2013

Where paragraph 1.E., ''Compliance,'' of Boeing Service Bulletin 747–53A2562, Revision 3, dated July 11, 2013, specifies a compliance time relative to the ''Revision 3 date of this service bulletin,'' this AD requires compliance within the specified compliance time after the effective date of this AD.

(l) NWW Modification for Certain Airplanes

For airplanes identified in Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012: At the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012, replace the left side, right side, and top panels of the NWW, as applicable, with new panels, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012. Concurrently with doing the replacement specified in this paragraph, do a detailed inspection for cracks of the attaching structural elements that are common to the removed top, left-side, and right-side panels of the NWW, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012. If any crack is found, before further flight, repair the cracking using a method approved in accordance with the procedures specified in paragraph (p) of this AD.

(m) Repetitive Post-Modification Inspections for Certain Airplanes

For airplanes on which the replacement specified in paragraph (l) of this AD has been done: At the applicable time specified in paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012, do the actions specified in paragraphs (m)(1), (m)(2), and (m)(3) of this AD. If any crack is found: Before further flight, repair the cracking using a method approved in accordance with the procedures specified in paragraph (p) of this AD. Repeat the inspections specified in paragraphs (m)(1), (m)(2), and (m)(3) of this AD thereafter at the applicable intervals specified in paragraph 1.E., ''Compliance,'' of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012.

(1) Do an external detailed inspection for cracks in the side panel webs, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012.

(2) Do an internal detailed inspection and HFEC inspection for cracks in the top and side panel stiffeners, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012.

(3) Do an external detailed inspection for cracks in the top panel web, in accordance with the Accomplishment Instructions of Boeing Alert Service Bulletin 747–53A2808, dated November 30, 2012.

(n) Terminating Action for Certain Repetitive Inspections

Replacing the left side, right side, and top panels of the NWW with new panels as specified in paragraph (i) or (l) of this AD terminates the repetitive inspections required by paragraph (g) of this AD.

(o) Credit for Previous Actions

(1) This paragraph restates the credit given in paragraph (k) of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006).

(i) This paragraph provides credit for the actions required by paragraph (g)(1) of this AD, if those actions were performed before January 27, 2005 (the effective date of AD 2004–25–23, Amendment 39–13911 (69 FR 76839, December 23, 2004)), using Boeing Alert Service Bulletin 747–53A2465, dated April 5, 2001, which is not incorporated by reference in this AD.

(ii) This paragraph provides credit for actions required by paragraphs (g)(1) and (g)(2) of this AD, if those actions were performed before December 11, 2006 (the effective date of AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006)), using a service bulletin identified in paragraph (o)(1)(ii)(A), (o)(1)(ii)(B), or (o)(1)(ii)(C) of this AD, which are not incorporated by reference in this AD.

(A) Boeing Alert Service Bulletin 747–53A2465, Revision 1, dated October 16, 2003.

(B) Boeing Alert Service Bulletin 747–53A2465, Revision 2, dated November 11, 2004.

(C) Boeing Alert Service Bulletin 747–53A2465, Revision 3, dated December 23, 2004.

(2) This paragraph provides credit for the actions required by paragraph (g) of this AD, if those actions were performed before the effective date of this AD using Boeing Alert Service Bulletin 747–53A2465, Revision 4, dated February 24, 2005, which is not incorporated by reference in this AD.

(3) This paragraph provides credit for the actions required by paragraphs (i) and (j) of this AD, if those actions were performed before the effective date of this AD using Boeing Service Bulletin 747–53A2562, Revision 1, dated July 28, 2005; or Boeing Service Bulletin 747–53A2562, Revision 2, dated May 31, 2007; which are not incorporated by reference in this AD.

(p) Alternative Methods of Compliance (AMOCs)

(1) The Manager, Seattle Aircraft Certification Office (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 paragraph (q)(1) of this AD. Information may be emailed to: *9-ANM-Seattle-ACO-AMOC-Requests@faa.gov.*

(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.

(3) An AMOC that provides an acceptable level of safety may be used for any repair required by this AD if it is approved the Boeing Commercial Airplanes Organization Designation Authorization (ODA) that has been authorized by the Manager, Seattle ACO, to make those findings. For a repair method to be approved, the repair must meet the certification basis of the airplane, and the approval must specifically refer to this AD.

(4) AMOC actions approved previously for AD 2006–22–15, Amendment 39–14812 (71 FR 64884, November 6, 2006), are approved as AMOCs for the corresponding actions of this AD. The compliance times in AMOCs approved previously for AD 2006–22–15 are not approved for the corresponding actions and compliance times in this AD.

(q) Related Information

(1) For more information about this AD, contact Bill Ashforth, Aerospace Engineer, Airframe Branch, ANM–120S, FAA, Seattle ACO, 1601 Lind Avenue SW., Renton, WA 98057–3356; phone: 425–917–6432; fax: 425–917–6590; email: *Bill.Ashforth@faa.gov.*

(2) For service information identified in this AD, Boeing Commercial Airplanes, Attention: Data & Services Management, P. O. Box 3707, MC 2H–65, Seattle, WA 98124–2207; telephone 206–544–5000, extension 1; fax 206–766–5680; Internet *https://www.myboeingfleet.com.* You may view this referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on September 1, 2015.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2015–23420 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

14 CFR Part 39

[Docket No. FAA–2015–3633; Directorate Identifier 2014–NM–097–AD]

RIN 2120–AA64

Airworthiness Directives; Fokker Services B.V. Airplanes

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of proposed rulemaking (NPRM).

SUMMARY: We propose to adopt a new airworthiness directive (AD) for all Fokker Services B.V. Model F.27 Mark 200, 300, 400, 500, 600, and 700 airplanes. This proposed AD was prompted by a design review conducted by Fokker Services B.V. that indicated no controlled bonding provisions were present on many critical locations outside the fuel tank or connected to the fuel tank wall. This proposed AD would require installing the additional bonding provisions, and revising the maintenance or inspection program, as applicable, by incorporating fuel airworthiness limitation items and critical design configuration control limitations. We are proposing this AD to prevent an ignition source in the fuel tank vapor space, which could result in a fuel tank explosion and consequent loss of the airplane.

DATES: We must receive comments on this proposed AD by November 2, 2015.

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:* U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC, between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays.

For service information identified in this proposed AD, contact Fokker Services B.V., Technical Services Dept., P.O. Box 1357, 2130 EL Hoofddorp, the Netherlands; telephone +31 (0)88–6280–350; fax +31 (0)88–6280–111; email *technicalservices@fokker.com;* Internet *http://www.myfokkerfleet.com.* You may view this referenced service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221.

Examining the AD Docket

You may examine the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3633; or in person at the Docket Management Facility between 9 a.m. and 5 p.m., Monday through Friday, except Federal holidays. The AD docket contains this proposed AD, the regulatory evaluation, any comments received, and other information. The street address for the Docket Operations office (telephone 800–647–5527) is in the **ADDRESSES** section. Comments will be available in the AD docket shortly after receipt.

FOR FURTHER INFORMATION CONTACT: Tom Rodriguez, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1137; fax 425–227–1149.

SUPPLEMENTARY INFORMATION:

Comments Invited

We invite you to send any written relevant data, views, or arguments about this proposed AD. Send your comments to an address listed under the **ADDRESSES** section. Include ''Docket No. FAA–2015–3633; Directorate Identifier 2014–NM–097–AD'' at the beginning of your comments. We specifically invite comments on the overall regulatory, economic, environmental, and energy aspects of this proposed AD. We will consider all comments received by the closing date and may amend this proposed AD based on 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 proposed AD.

Discussion

The European Aviation Safety Agency (EASA), which is the Technical Agent for the Member States of the European Union, has issued EASA Airworthiness Directive 2014–0100, dated April 30, 2014 (referred to after this as the Mandatory Continuing Airworthiness Information, or ''the MCAI''), to correct an unsafe condition for all Fokker Services B.V. Model F.27 Mark 200, 300, 400, 500, 600, and 700 airplanes. The MCAI states:

> Prompted by an accident * * *, the FAA published Special Federal Aviation Regulation (SFAR) 88 [(66 FR 23086, May 7, 2001)], and the Joint Aviation Authorities (JAA) published Interim Policy INT/POL/25/12.
>
> The review conducted by Fokker Services on the Fokker 27 design in response to these regulations revealed that no controlled bonding provisions are present on a number of critical locations outside the fuel tanks.
>
> This condition, if not corrected, could create an ignition source in the fuel tank vapour space, possibly resulting in a fuel tank explosion and consequent loss of the aeroplane.
>
> To address this potential unsafe condition, Fokker Services developed a set of bonding modifications, introduced with [a service bulletin] * * *, that do[es] not require opening of the fuel tank access panels.
>
> More information on this subject can be found in Fokker Services All Operators Message AOF27.043#03.
>
> For the reasons described above, this [EASA] AD requires installation of additional bonding provisions that do not require opening of the fuel tank access panels.

Required actions also include revising the maintenance or inspection program, as applicable, by incorporating fuel airworthiness limitation items and critical design configuration control limitations. You may examine the MCAI in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3633.

The FAA has examined the underlying safety issues involved in fuel tank explosions on several large transport airplanes, including the adequacy of existing regulations, the service history of airplanes subject to those regulations, and existing maintenance practices for fuel tank systems. As a result of those findings, we issued a regulation titled ''Transport Airplane Fuel Tank System Design Review, Flammability Reduction and Maintenance and Inspection Requirements'' (66 FR 23086, May 7, 2001). In addition to new airworthiness standards for transport airplanes and new maintenance requirements, this rule included Special Federal Aviation Regulation No. 88 (''SFAR 88,'' Amendment 21–78, and subsequent Amendments 21–82 and 21–83).

Among other actions, SFAR 88 (66 FR 23086, May 7, 2001) requires certain type design (*i.e.,* type certificate (TC) and supplemental type certificate (STC)) holders to substantiate that their fuel tank systems can prevent ignition sources in the fuel tanks. This requirement applies to type design holders for large turbine-powered transport airplanes and for subsequent modifications to those airplanes. It requires them to perform design reviews and to develop design changes and maintenance procedures if their designs do not meet the new fuel tank safety standards. As explained in the preamble to the rule, we intended to adopt airworthiness directives to mandate any changes found necessary to address unsafe conditions identified as a result of these reviews.

In evaluating these design reviews, we have established four criteria intended to define the unsafe conditions associated with fuel tank systems that require corrective actions. The percentage of operating time during which fuel tanks are exposed to flammable conditions is one of these criteria. The other three criteria address the failure types under evaluation: Single failures, single failures in combination with a latent condition(s), and in-service failure experience. For all four criteria, the evaluations included consideration of previous actions taken that may mitigate the need for further action.

The Joint Aviation Authorities (JAA) has issued a regulation that is similar to SFAR 88 (66 FR 23086, May 7, 2001). (The JAA is an associated body of the European Civil Aviation Conference (ECAC) representing the civil aviation regulatory authorities of a number of European States who have agreed to co-operate in developing and implementing common safety regulatory standards and procedures.) Under this regulation, the JAA stated that all members of the ECAC that hold type certificates for transport category airplanes are required to conduct a design review against explosion risks.

We have determined that the actions identified in this AD are necessary to reduce the potential of ignition sources inside fuel tanks, which, in combination with flammable fuel vapors, could result in fuel tank explosions and consequent loss of the airplane.

Related Service Information Under 1 CFR Part 51

Fokker Services B.V. has issued F27 Proforma Service Bulletin SBF27–28–072, Revision 1, dated March 6, 2014, including Fokker F27 Service Bulletin Appendix SBF27–28–072/APP01, including List of Drawings/Part Lists, dated July 17, 2014; and Fokker Manual Change Notification—Maintenance Documentation (MCNM) F27–027 dated September 9, 2014. The service information describes procedures for installing additional bonding provisions. This service information is reasonably available because the interested parties have access to it through their normal course of business or by the means identified in the **ADDRESSES** section of this NPRM.

FAA's Determination and Requirements of This Proposed AD

This product has been approved by the aviation authority of another country, and is approved for operation in the United States. Pursuant to our bilateral agreement with the State of Design Authority, we have been notified of the unsafe condition described in the MCAI and service information referenced above. We are proposing this AD because we evaluated all pertinent information and determined an unsafe condition exists and is likely to exist or develop on other products of this same type design.

This proposed AD requires revisions to certain operator maintenance documents to include new inspections. Compliance with these inspections is required by section 91.403(c) of the Federal Aviation Regulations (14 CFR 91.403(c)). For airplanes that have been previously modified, altered, or repaired in the areas addressed by these inspections, an operator might not be able to accomplish the inspections described in the revisions. In this situation, to comply with 14 CFR 91.403(c), the operator must request approval of an alternative method of compliance (AMOC) in accordance with the provisions of paragraph (j) of this proposed AD. The request should include a description of changes to the required inspections that will ensure the continued operational safety of the airplane.

Costs of Compliance

We estimate that this proposed AD affects 15 airplanes of U.S. registry.

We also estimate that it would take about 8 work-hours per product to comply with the basic requirements of this proposed AD. The average labor rate is $85 per work-hour. Based on these figures, we estimate the cost of this proposed AD on U.S. operators to be $10,200, or $680 per product.

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

We determined that this proposed AD would not have federalism implications under Executive Order 13132. This proposed AD would 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 this proposed regulation:

1. Is not a ''significant regulatory action'' under Executive Order 12866;
2. Is not a ''significant rule'' under the 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.

The Proposed Amendment

Accordingly, under the authority delegated to me by the Administrator, the FAA proposes to amend 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):

Fokker Services B.V.: Docket No. FAA–2015–3633; Directorate Identifier 2014–NM–097–AD.

(a) Comments Due Date

We must receive comments by November 2, 2015.

(b) Affected ADs

None.

(c) Applicability

This AD applies to Fokker Services B.V. Model F.27 Mark 200, 300, 400, 500, 600, and 700 airplanes, certificated in any category, all serial numbers.

(d) Subject

Air Transport Association (ATA) of America Code 28, Fuel.

(e) Reason

This AD was prompted by a design review conducted by Fokker Services B.V. that indicated no controlled bonding provisions were present on many critical locations outside the fuel tank or connected to the fuel tank wall. We are issuing this AD to prevent an ignition source in the fuel tank vapor space, which could result in a fuel tank explosion and consequent loss of the airplane.

(f) Compliance

Comply with this AD within the compliance times specified, unless already done.

(g) Installation

Within 24 months after the effective date of this AD, install additional bonding provisions, in accordance with the Accomplishment Instructions of Fokker F27 Proforma Service Bulletin SBF27–28–072, Revision 1, dated March 6, 2014, including Fokker F27 Service Bulletin Appendix SBF27–28–072/APP01, including List of Drawings/Part Lists, dated July 17, 2014.

(h) Maintenance or Inspection Program Revision

At the later of the times specified in paragraph (h)(1) and (h)(2) of this AD: Revise the airplane maintenance or inspection program, as applicable, by incorporating the fuel airworthiness limitations items and critical design configuration control limitations as identified in Fokker Manual Change Notification—Maintenance Documentation (MCNM) F27–027 dated September 9, 2014.

(1) Before further flight after accomplishing the installation required by paragraph (g) of this AD,

(2) Within 30 days after the effective date of this AD.

(i) No Alternative Actions, Intervals, and/or Critical Design Configuration Control Limitations (CDCCLs)

After the maintenance or inspection program, as applicable, has been revised as required by paragraph (h) of this AD, no alternative actions (*e.g.,* inspections), intervals, and/or CDCCLs may be used unless the actions, intervals, and/or CDCCLs are approved as an alternative method of compliance in accordance with the procedures specified in paragraph (j) of this AD.

(j) Other FAA AD Provisions

The following provisions also apply to this AD:

(1) *Alternative Methods of Compliance (AMOCs):* The Manager, International Branch, ANM–116, Transport Airplane Directorate, 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 International Branch, send it to ATTN: Tom Rodriguez, Aerospace Engineer, International Branch, ANM–116, Transport Airplane Directorate, FAA, 1601 Lind Avenue SW., Renton, WA 98057–3356; telephone 425–227–1137; fax 425 227–1149 Information may be emailed to: *9-ANM-116-AMOC-REQUESTS@faa.gov.* 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. The AMOC approval letter must specifically reference this AD.

(2) *Contacting the Manufacturer:* For any requirement in this AD to obtain corrective actions from a manufacturer, the action must be accomplished using a method approved by the Manager, International Branch, ANM–116, Transport Airplane Directorate, FAA; or the European Aviation Safety Agency (EASA); or Fokker B.V. Service's EASA Design Organization Approval (DOA). If approved by the DOA, the approval must include the DOA-authorized signature.

(k) Related Information

(1) Refer to Mandatory Continuing Airworthiness Information (MCAI) EASA Airworthiness Directive 2014–0100, dated April 30, 2014, for related information. This MCAI may be found in the AD docket on the Internet at *http://www.regulations.gov* by searching for and locating Docket No. FAA–2015–3633.

(2) For service information identified in this AD, contact Fokker Services B.V., Technical Services Dept., P.O. Box 1357, 2130 EL Hoofddorp, the Netherlands; telephone +31 (0)88–6280–350; fax +31 (0)88–6280–111; email *technicalservices@fokker.com;* Internet *http://www.myfokkerfleet.com.* You may view this service information at the FAA, Transport Airplane Directorate, 1601 Lind Avenue SW., Renton, WA. For information on the availability of this material at the FAA, call 425–227–1221.

Issued in Renton, Washington, on September 11, 2015.

Michael Kaszycki,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 2015–23408 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[REG–127895–14]

RIN 1545–BM33

Dividend Equivalents From Sources Within the United States

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Notice of proposed rulemaking by cross-reference to temporary regulations and notice of public hearing.

SUMMARY:

DATES: Written or electronic comments must be received by December 17, 2015. Outlines of topics to be discussed at the public hearing scheduled for January 15, 2016, at 10 a.m. must be received by December 17, 2015.

ADDRESSES: Send submissions to CC:PA:LPD:PR (REG–127895–14), Room 5203, Internal Revenue Service, PO Box 7604, Ben Franklin Station, Washington, DC 20044. Submissions may be hand delivered Monday through Friday between the hours of 8 a.m. and 4 p.m. to CC:PA:LPD:PR (REG–127895–14), Courier's desk, Internal Revenue Service, 1111 Constitution Avenue NW., Washington, DC 20044, or sent electronically, via the Federal eRulemaking Portal at *www.regulations.gov* (IRS REG–127895–14). The public hearing will be held in the IRS Auditorium, Internal Revenue Building, 1111 Constitution Avenue NW., Washington, DC.

FOR FURTHER INFORMATION CONTACT: Concerning the regulations, D. Peter Merkel or Karen Walny at (202) 317–6938; concerning submissions of comments, the hearing, and/or to be placed on the building access list to attend the hearing Oluwfunmilayo Taylor at (202) 317–6901 (not toll-free numbers).

SUPPLEMENTARY INFORMATION:

Background and Explanation of Provisions

Final and temporary regulations in the Rules and Regulations section of this issue of the **Federal Register** contain amendments to the Income Tax Regulations (26 CFR part 1) which provide rules for determining when a payment made pursuant to certain financial products will be treated as a dividend equivalent for purposes of section 871(m). These proposed regulations provide guidance relating to the substantial equivalence test, which is used to determine whether a complex contract is a section 871(m) transaction. These proposed regulations also provide guidance to qualified derivatives dealers. The text of those temporary regulations also serves as the text of these proposed regulations. The preamble to the final and temporary regulations explains the temporary regulations and these proposed regulations. The regulations affect nonresident alien individuals, foreign corporations, and withholding agents.

Special Analyses

Certain IRS regulations, including this one, are exempt from the requirements of Executive Order 12866, as supplemented and reaffirmed by Executive Order 13563. Therefore, a regulatory impact assessment is not required. It has also been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations, and because the regulations do not impose a collection of information on small entities, the Regulatory Flexibility Act (5 U.S.C. chapter 6) does not apply. Pursuant to section 7805(f), these regulations have been submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

Comments and Public Hearing

Before these proposed regulations are adopted as final regulations, consideration will be given to any comments that are submitted timely to the IRS as prescribed in this preamble under the **ADDRESSES** heading. The Treasury Department and the IRS request comments on all aspects of the proposed rules. All comments will be available at *www.regulations.gov* or upon request.

A public hearing has been scheduled for January 15, 2016, beginning at 10 a.m. in the Auditorium of the Internal Revenue Building, 1111 Constitution Avenue NW., Washington, DC. Due to building security procedures, visitors must enter at the Constitution Avenue entrance. In addition, all visitors must present photo identification to enter the building. Because of access restrictions, visitors will not be admitted beyond the immediate entrance more than 30 minutes before the hearing starts. For information about having your name placed on the building access list to attend the hearing, see the **FOR FURTHER INFORMATION CONTACT** section of this preamble.

The rules of 26 CFR 601.601(a)(3) apply to the hearing. Persons who wish to present oral comments at the hearing must submit an outline of the topics to be discussed and the time to be devoted to each topic by December 17, 2015. Submit a signed paper or electronic copy of the outline as prescribed in this preamble under the **ADDRESSES** heading. A period of 10 minutes will be allotted to each person for making comments. An agenda showing the scheduling of the speakers will be prepared after the deadline for receiving outlines has passed. Copies of the agenda will be available free of charge at the hearing.

Drafting Information

The principal authors of these regulations are D. Peter Merkel and Karen Walny of the Office of Chief Counsel (International). However, other personnel from the Treasury Department and the IRS participated in their development.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Proposed Amendments to the Regulations

Accordingly, 26 CFR part 1 is proposed to be amended as follows:

PART 1—INCOME TAXES

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

Authority: 26 U.S.C. 7805 * * *

§ 1.871–15 also issued under 26 U.S.C. 871(m). * * *

■ **Par. 2.** Section 1.871–15 is amended by revising paragraph (c)(2)(vi) and paragraph (h) to read as follows:

§ 1.871–15 Treatment of dividend equivalents.

* * * * *

(c) * * *

(2) * * *

(iv) [The text of the proposed amendments to § 1.871–15(c)(2)(iv) is the same as the text of § 1.871–15T(c)(2)(iv) published elsewhere in this issue of the **Federal Register**.]

* * * * *

(h) [The text of the proposed amendments to § 1.871–15(h) is the same as the text of § 1.871–15T(h) published elsewhere in this issue of the **Federal Register**.]

* * * * *

(q) [The text of the proposed amendments to § 1.871–15(q) is the same as the text of § 1.871–15T(q) published elsewhere in this issue of the **Federal Register**.]

■ **Par. 3.** Section 1.1441–1 is amended by revising paragraph (e)(3)(vii) and paragraph (e)(6) to read as follows:

§ 1.1441–1 Requirement for the deduction and withholding of tax on payments to foreign persons.

* * * * *

(e) * * *

(3) * * *

(ii) * * *

(E) [The text of the proposed amendments to § 1.1441–1(e)(3)(ii)(E) is the same as the text of § 1.1441–1T(e)(3)(ii)(E) published elsewhere in this issue of the **Federal Register.**]

* * * * *

(5) [The text of the proposed amendments to § 1.1441–1(e)(5) is the same as the text of § 1.1441–1T(e)(5) published elsewhere in this issue of the **Federal Register**.]

(6) [The text of the proposed amendments to § 1.1441–1(e)(6) is the same as the text of § 1.1441–1T(e)(6) published elsewhere in this issue of the **Federal Register**.]

John Dalrymple,

Deputy Commissioner for Services and Enforcement.

[FR Doc. 2015–21753 Filed 9–17–15; 8:45 am]

BILLING CODE 4830–01–P

DEPARTMENT OF LABOR

Mine Safety and Health Administration

30 CFR Parts 7 and 75

[Docket No. MSHA–2013–0033]

RIN 1219–AB79

Refuge Alternatives for Underground Coal Mines

AGENCY: Mine Safety and Health Administration, Labor.

ACTION: Notice of public meeting; reopening of record.

SUMMARY: The Mine Safety and Health Administration (MSHA) will hold a public meeting to gather information on issues and options relevant to miners' escape and refuge. This meeting will supplement the information already received in response to the Agency's Request for Information on Refuge Alternatives for Underground Coal Mines. This meeting provides coal mine operators, coal miners, manufacturers, academia and other interested stakeholders an opportunity to provide information concerning two critical issues: Impediments to the use of built-in-place refuges and enhanced two-way voice communication when using escape breathing devices. This meeting also invites stakeholders to provide input on the current state of refuges in use and recent research and new

technology that may lead to the development of a new generation of refuges. MSHA also is reopening the record for public comment.

DATES: The public meeting will be held on October 19, 2015. All written submissions or responses for the record, including relevant data and information, must be received by midnight Eastern Standard Time on November 16, 2015.

ADDRESSES: The public meeting will be held at MSHA's National Mine Health and Safety Academy, 1301 Airport Road, Beaver, West Virginia 25813–9426.

Requests to speak or make a presentation at the meeting may be made to Leah Davis at 202–693–9440 or by one of the following methods:

- *Fax:* 202–693–9441.
- *Electronic Mail: davis.leah@dol.gov.*
- *Mail:* MSHA, Office of Standards, Regulations, and Variances, 201 12th Street South, Suite 4E401, Arlington, Virginia 22202–5452.

Instructions: All submissions must include RIN 1219–AB79 or Docket No. MSHA–2013–0033. Do not include personal information that you do not want publicly disclosed; MSHA will post all submissions without change to *http://www.regulations.gov,* including any personal information provided.

For additional instructions for participation in the public meeting, see the **SUPPLEMENTARY INFORMATION** section of this notice.

Docket: For access to the docket to read comments received, go to *http://www.regulations.gov* or *http://www.msha.gov/currentcomments.asp.* To read background documents, go to *http://www.regulations.gov.* Review the docket in person at MSHA, Office of Standards, Regulations, and Variances, 201 12th Street South, Suite 4E401, Arlington, Virginia, between 9:00 a.m. and 5:00 p.m. Monday through Friday, except Federal holidays. Sign in at the receptionist's desk in Suite 4E401.

Email Notification: To subscribe to receive an email notification when MSHA publishes rules, program information, instructions, or policy, in the **Federal Register**, go to *http://www.msha.gov/subscriptions/subscribe.aspx.*

FOR FURTHER INFORMATION CONTACT: Sheila A. McConnell, Acting Director, Office of Standards, Regulations, and Variances, MSHA, at *mcconnell.sheila.a@dol.gov* (email), 202–693–9440 (voice), or 202–693–9441 (facsimile). These are not toll-free numbers.

SUPPLEMENTARY INFORMATION:

I. Public Meeting

MSHA invites coal mine operators, coal miners, equipment manufacturers, academia, and the public to provide information on the current state of refuge alternatives, particularly on the challenges related to the use of built-in-place refuges, and enhancing voice communication when using escape breathing devices. MSHA especially invites coal miners and operators of small underground coal mines to participate.

The information from this meeting will supplement comments to the Agency's Request for Information and research from the National Institute for Occupational Safety and Health (NIOSH). This meeting will focus on four primary issues: Challenges related to built-in-place refuges; miners communicating while using breathing devices during escape; advantages and disadvantages of self-contained breathing apparatus (SCBA) with refill stations as an escape strategy; and the scope and status of new technology or recent research related to the installation and use of built-in-place refuges.

The public meeting will be held in the auditorium at MSHA's National Mine Health and Safety Academy on October 19, 2015, beginning with Registration at 1 p.m. and concluding at 5 p.m. or when the last speaker has spoken.

The meeting will be conducted in an informal manner. Presenters and attendees may provide written information to the court reporter for inclusion in the rulemaking record. MSHA will make the transcript of the meeting available on *www.regulations.gov* and on the Agency's Web site at *http://www.msha.gov/tscripts.htm* and include it in the rulemaking record.

II. Background

Continued development of refuge equipment and technology is expected to enhance the effectiveness of refuges and improve miners' chances of surviving a mine emergency when escape is impossible. Since the refuge alternatives rule became effective on March 2, 2009, stakeholders have gained experience, and research has led to some technological advancements and innovations. To benefit from this experience and research, on August 8, 2013, MSHA published a Request for Information (RFI) in the **Federal Register** (78 FR 48593) asking for data, comments, and information on issues and options that may present alternative or even more effective solutions for miners' survival during underground coal mine emergencies than the protections provided by the existing rule.

In response to requests, MSHA extended the comment period four times to give interested parties additional time to review research reports from NIOSH and other relevant information and provide substantive comments. The comment period closed on April 2, 2015.

III. Questions and Issues for Discussion

A. Built-In-Place Refuge Alternatives

In its report, ''Facilitating the Use of Built-In-Place Refuge Alternatives in Mines,'' RI 9698, NIOSH makes recommendations on the use of built-in-place shelters, as a type of refuge with a superior environment when compared to tent and steel pre-fabricated structures. The report addresses three issues: (1) Locating built-in-place refuges further from the face than the 1,000-foot limit required under the existing standard; (2) providing a consistent process for the design and approval of refuge stoppings; and (3) delivering a reliable supply of clean, breathable air to a built-in-place refuge. NIOSH recommends allowing operators to locate built-in-place refuges further than 1,000 feet from the face, but only if the refuges:

- Provide a constant supply of air into the refuge via either a protected compressed air line or a borehole from the surface.
- Provide a minimum of 85 cubic feet of space per occupant.
- Maintain the interior of the refuge under positive pressure when not in use to ensure that the refuge contains breathable air immediately on entry and to keep contaminated air from entering the refuge when miners enter.

MSHA invites comments and information on the following issues:

1. How would MSHA's acceptance of built-in-place refuges located further from the face and meeting the above criteria affect your decision on whether or not to install a built-in-place refuge? Discuss the relative merits of location versus design and performance. Please comment on the advantages and disadvantages of NIOSH's recommended approach for built-in-place refuges; the feasibility of installing built-in-place shelters in different mine settings; the risks related to a refuge location that is further away from the working face; and the benefits of a built-in-place refuge's environment and performance characteristics.

2. Discuss the advantages and disadvantages of the following methods of providing breathable air in refuges:

Using supplied air from the surface versus using air from cylinders stored underground; or delivering surface-supplied air through a borehole directly into a built-in-place refuge versus compressed air lines run through the mine.

3. Discuss options for piping air over several miles through a mine to provide a clean air supply and sufficient air pressure to a built-in-place refuge when a borehole directly into the refuge is unavailable. What issues remain to be addressed for the protection of piping used to provide compressed air to a refuge?

4. What are the risks and benefits to miners' safety, if any, if a constant air supply from the surface is provided to a refuge and exhausted from the refuge into the mine, as opposed to exhausting to the surface?

5. What are the advantages and disadvantages of using SCBAs with refill stations as compared to using SCSRs with caches in escapeways?

6. Discuss and describe new and improved technology for built-in-place refuges' designs. What is the impact of these designs on the cost of built-in-place refuges? For example, would a moveable wall or other modular design make the use of a built-in-place refuge more feasible and economical?

B. Miners' Ability To Communicate During Escape

Miners' ability to communicate with each other can be critical during mine emergencies. Under existing rules, miners use self-contained self-rescue (SCSR) escape respirators that have a mouthpiece. A self-contained breathing apparatus (SCBA) has a full-face respirator mask. Miners must remove the mouthpiece of an SCSR to speak, or remove the full-face respirator mask of an SCBA to communicate clearly. These actions expose miners to deadly gases in the mine atmosphere.

7. Discuss the challenges associated with providing two-way communication when using escape SCBAs or SCSRs. What technologies, such as voice amplifiers or wireless communication systems, are available for escape SCBAs or SCSRs that can enhance voice communication among miners?

8. Discuss how this technology can be integrated with a mine's two-way post-accident communication system.

MSHA will accept written responses, data, and information for the record from any interested party, including those not participating in the public meeting, through November 16, 2015.

Joseph A. Main,

Assistant Secretary of Labor for Mine Safety and Health.

[FR Doc. 2015–23448 Filed 9–17–15; 8:45 am]

BILLING CODE 4510–43–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 52

[EPA–R04–OAR–2014–0904; FRL–9934–26–Region 4]

Air Plan Approval; TN; Reasonably Available Control Measures and Redesignation for the TN Portion of the Chattanooga 1997 Annual $PM_{2.5}$ Nonattainment Area

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule; supplemental.

SUMMARY: The Environmental Protection Agency (EPA) is proposing two separate but related actions pertaining to the Tennessee portion of the Chattanooga nonattainment area for the 1997 annual fine particulate matter ($PM_{2.5}$) national ambient air quality standards (NAAQS) (hereinafter referred to as the ''Chattanooga TN–GA–AL Area'' or ''Area''). First, EPA is proposing to approve the portion of the attainment plan state implementation plan (SIP) revision submitted by the State of Tennessee, through the Tennessee Department of Environment and Conservation (TDEC), on October 15, 2009, that addresses reasonably available control measures (RACM), including reasonably available control technology (RACT), for the Tennessee portion of the Area. EPA is not proposing to act on the portions of the SIP revision that are unrelated to RACM. Second, EPA is supplementing the Agency's March 27, 2015, proposed approval of Tennessee's November 13, 2014, redesignation request for the Tennessee portion of the Area by proposing that approval of the RACM portion of the aforementioned SIP revision satisfies the applicable RACM requirements for redesignation under the Clean Air Act (CAA or Act).

DATES: Comments must be received on or before October 9, 2015.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R04–OAR–2014–0904, by one of the following methods:

1. *www.regulations.gov:* Follow the on-line instructions for submitting comments.

2. *Email: R4-ARMS@epa.gov.*

3. *Fax:* (404) 562–9019.

4. *Mail:* ''EPA–R04–OAR–2014–0904,'' Air Regulatory Management Section, Air Planning and Implementation Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960.

5. *Hand Delivery or Courier:* Lynorae Benjamin, Chief, Air Regulatory Management Section, Air Planning and Implementation Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Such deliveries are only accepted during the Regional Office's normal hours of operation. The Regional Office's official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

Instructions: Direct your comments to Docket ID No. EPA–R04–OAR–2014–0904. 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 through *www.regulations.gov* or email, information that you consider to be CBI or otherwise protected. 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.*

Docket: All documents in the electronic docket are listed in the *www.regulations.gov* index. Although listed in the index, some information may not be publicly available, *i.e.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Air Regulatory Management Section, Air Planning and Implementation Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. EPA requests that if at all possible, you contact the person listed in the **FOR FURTHER INFORMATION CONTACT** section to schedule your inspection. The Regional Office's official hours of business are Monday through Friday, 8:30 a.m. to 4:30 p.m., excluding Federal holidays.

FOR FURTHER INFORMATION CONTACT: Joel Huey, Air Planning and Implementation Branch, Air, Pesticides and Toxics Management Division, U.S. Environmental Protection Agency, Region 4, 61 Forsyth Street SW., Atlanta, Georgia 30303–8960. Mr. Huey's phone number is (404) 562–9104. He can also be reached via electronic mail at *huey.joel@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. Background

On July 18, 1997, EPA promulgated the first air quality standards for $PM_{2.5}$. EPA promulgated an annual standard at a level of 15 micrograms per cubic meter ($\mu g/m^3$) (based on a 3-year average of annual mean $PM_{2.5}$ concentrations) and a 24-hour standard of 65 $\mu g/m^3$ (based on a 3-year average of the 98th percentile of 24-hour concentrations). *See* 62 FR 36852. On January 5, 2005, and supplemented on April 14, 2005, EPA designated Hamilton County in Tennessee, in association with counties in Alabama and Georgia in the Chattanooga TN-GA-AL Area, as nonattainment for the 1997 Annual $PM_{2.5}$ NAAQS. *See* 70 FR 944 and 70 FR 19844, respectively. Designation of an area as nonattainment for $PM_{2.5}$ starts the process for a state to develop and submit to EPA an attainment plan SIP revision under title I, part D of the CAA. This SIP revision must include, among other elements, a demonstration of how the NAAQS will be attained in the nonattainment area as expeditiously as practicable, but no later than the attainment date required by the CAA.

EPA designated all 1997 $PM_{2.5}$ NAAQS areas under title I, part D, subpart 1 (hereinafter ''Subpart 1''). Subpart 1 contains the general requirements for nonattainment areas for criteria pollutants and is less prescriptive than the other subparts of title I, part D. On April 25, 2007, EPA promulgated a rule, codified at 40 CFR part 51, subpart Z, to implement the 1997 $PM_{2.5}$ NAAQS under Subpart 1 (hereinafter referred to as the ''1997 $PM_{2.5}$ Implementation Rule'').[1] *See* 72 FR 20586. On October 15, 2009, Tennessee submitted an attainment plan SIP revision pursuant to Subpart 1 and the 1997 $PM_{2.5}$ Implementation Rule that addressed RACM and contained a reasonable further progress (RFP) plan, base-year and attainment-year emissions inventories, and contingency measures for the Area.

On May 31, 2011 (76 FR 31239), EPA published a final determination that the Chattanooga TN-GA-AL Area had attained the 1997 Annual $PM_{2.5}$ NAAQS based upon quality-assured and certified ambient air monitoring data for the 2007–2009 time period. In that determination and in accordance with the 1997 $PM_{2.5}$ Implementation Rule at 40 CFR 51.1004(c), EPA suspended the requirements for the Chattanooga TN-GA-AL Area to submit attainment demonstrations and associated RACM, RFP plans, contingency measures, and other planning SIPs related to attainment of the 1997 Annual $PM_{2.5}$ NAAQS, so long as the Area continues to attain the 1997 Annual $PM_{2.5}$ NAAQS. *See* 40 CFR 52.2231(c); 76 FR 31239.

Tennessee submitted a request to EPA on November 13, 2014, to redesignate the State's portion of the Chattanooga TN-GA-AL Area to attainment for the 1997 Annual $PM_{2.5}$ NAAQS and to approve a SIP revision containing a maintenance plan for the Tennessee portion of the Area. EPA proposed to approve the redesignation request and the related SIP revision in an action signed on March 11, 2015, based, in part, on the Agency's longstanding interpretation that Subpart 1 nonattainment planning requirements, including RACM, are not ''applicable'' for purposes of CAA section 107(d)(3)(E)(ii) once an area is attaining the NAAQS and, therefore, need not be approved into the SIP before EPA can redesignate the area. *See* 80 FR 16331 (March 27, 2015).

On March 18, 2015, the United States Court of Appeals for the Sixth Circuit (Sixth Circuit) issued an opinion in *Sierra Club* v. *EPA,* 781 F.3d 299 (6th Cir. 2015), that is inconsistent with this longstanding interpretation regarding section 107(d)(3)(E)(ii). In its decision, the Court vacated EPA's redesignation of the Indiana and Ohio portions of the Cincinnati-Hamilton nonattainment area to attainment for the 1997 $PM_{2.5}$ NAAQS because EPA had not yet approved Subpart 1 RACM for the Cincinnati Area into the Indiana and Ohio SIPs.[2] The Court concluded that ''a State seeking redesignation 'shall provide for the implementation' of RACM/RACT, even if those measures are not strictly necessary to demonstrate attainment with the $PM_{2.5}$ NAAQS . . . . If a State has not done so, EPA cannot 'fully approve[]' the area's SIP, and redesignation to attainment status is improper.'' *Sierra Club,* 781 F.3d at 313.

II. What are EPA's proposed actions?

EPA is bound by the Sixth Circuit's decision in *Sierra Club* v. *EPA* within the Court's jurisdiction unless it is overturned.[3] Although EPA continues to believe that Subpart 1 RACM is not an applicable requirement under section 107(d)(3)(E) for an area that has already attained the 1997 Annual $PM_{2.5}$ NAAQS, EPA is proposing two separate but related actions regarding the Tennessee portion of the Chattanooga

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[1] On January 4, 2013, in *Natural Resources Defense Council* v. *EPA,* 706 F.3d 428 (D.C. Cir. 2013), the United States Court of Appeals for the District of Columbia Circuit (D.C. Circuit) found that EPA erred in implementing the 1997 $PM_{2.5}$ NAAQS pursuant solely to the general implementation provisions of Subpart 1 rather than the particulate matter-specific provisions of title I, part D, subpart 4. The court remanded both the 1997 $PM_{2.5}$ Implementation Rule and the final rule entitled ''Implementation of the New Source Review (NSR) Program for Particulate Matter Less than 2.5 Micrometers ($PM_{2.5}$)'' (73 FR 28321, May 16, 2008) to EPA to address this error.

[2] The Court issued an amended decision on July 14, 2015, revising some of the legal aspects of the Court's analysis of the relevant statutory provisions (section 107(d)(3)(E)(ii) and section 172(c)(1)) but maintaining its prior holding that section 172(c)(1) ''unambiguously requires implementation of RACM/RACT prior to redesignation . . . even if those measures are not strictly necessary to demonstrate attainment with the $PM_{2.5}$ NAAQS.'' *See Sierra Club* v. *EPA,* Nos. 12–3169, 12–3182, 12–3420 (6th Cir. July 14, 2015).

[3] The states of Kentucky, Michigan, Ohio, and Tennessee are located within the Sixth Circuit's jurisdiction.

TN-GA-AL Area in response to the Court's decision.[4] [5]

First, EPA is proposing to approve the portion of the State's October 15, 2009, attainment plan SIP revision that addresses RACM under Subpart 1 for the Tennessee portion of the Area. Second, EPA is supplementing the Agency's proposed approval of Tennessee's November 13, 2014, redesignation request for the Area by proposing that approval of the RACM portion of the aforementioned SIP revision satisfies the Subpart 1 RACM requirement in accordance with section 107(d)(3)(E) of the CAA. More detail on EPA's rationale for these proposed actions is provided below.

III. What is EPA's analysis of the state's RACM submittal?

a. Subpart 1 RACM Requirements

Subpart 1 requires that each attainment plan ''provide for the implementation of all reasonably available control measures as expeditiously as practicable (including such reductions in emissions from the existing sources in the area as may be obtained through the adoption, at a minimum, of reasonably available control technology), and shall provide for attainment of the national primary ambient air quality standards.'' *See* CAA section 172(c)(1). EPA interprets RACM, including RACT, under section 172(c)(1) as measures that are both reasonably available and necessary to demonstrate attainment as expeditiously as practicable in the nonattainment area. *See* 40 CFR 51.1010(a).[6] A state must adopt, as RACM, measures that are reasonably available considering technical and economic feasibility if, considered collectively, they would advance the attainment date by one year or more. *See* 40 CFR 51.1010(b).

The $PM_{2.5}$ Implementation Rule requires that the Subpart 1 RACM portion of the attainment plan SIP revision include the list of potential measures that a state considered and information sufficient to show that the state met all requirements for the determination of what constitutes RACM in a specific nonattainment area. *See* 40 CFR 51.1010(a). Any measures that are necessary to meet these requirements which are not already either federally promulgated, part of the state's implementation plan, or otherwise creditable in SIPs must be submitted in enforceable form as part of a state's attainment plan SIP revision for the area. As discussed above, an attainment determination suspends the requirement for a $PM_{2.5}$ nonattainment area to submit an attainment plan SIP revision so long as the area continues to attain the $PM_{2.5}$ NAAQS. *See* 40 CFR 51.1004(c).

b. Proposed Action on RACM Based Upon Attainment of the NAAQS

EPA is proposing to approve the portion of Tennessee's October 15, 2009, attainment plan SIP revision that addresses Subpart 1 RACM for the State's portion of the Area on the basis that the Area has attained the 1997 Annual $PM_{2.5}$ NAAQS and, therefore, no emission reduction measures are necessary to satisfy Subpart 1 RACM. As noted above, EPA has determined that the Area has attaining data for the 1997 Annual $PM_{2.5}$ NAAQS and met the standard by the April 5, 2010, attainment date. *See* 77 FR 31239. Because the Area has attained the standard, there are no emissions controls that could advance the attainment date; thus, no emissions controls are necessary to satisfy Subpart 1 RACM pursuant to 40 CFR 51.1010 (defining RACM as the level of control necessary to advance the attainment date by one year or more).

c. Proposed Action on RACM Based Upon the State's Control Evaluation

Additionally, the portion of Tennessee's October 15, 2009, attainment plan SIP revision that addresses Subpart 1 RACM for the State's portion of the Area is approvable on the basis that the SIP revision demonstrates that no additional reasonably available controls would have advanced the attainment date projected therein.

Through participation in the regional planning efforts of the Visibility Improvement States and Tribal Association of the Southeast (VISTAS) and the Association for Southeastern Integrated Planning (ASIP), Tennessee determined that existing measures and measures planned for implementation by 2009 would result in the Chattanooga TN-GA-AL Area attaining the 1997 $PM_{2.5}$ NAAQS by the end of 2009. Air quality modeling conducted by ASIP indicated that the Area would attain the annual NAAQS in 2009 based upon projected emissions reductions from sources within the Area after 2002 (the base year of the nonattainment emissions inventory). As discussed in Chapter 2.0 of the October 15, 2009, SIP revision, the State, in consultation with VISTAS and ASIP, considered the following existing federally enforceable measures in projecting the emissions inventory used for the 2009 modeling: Tier 2 vehicle standards; heavy-duty gasoline and diesel highway vehicle standards; large nonroad diesel engine standards; nonroad spark-ignition engines and recreational engines standards; NO_X SIP call; and the Clean Air Interstate Rule.

In Tennessee's RACM analysis, which appears in chapter 4.0 of the October 15, 2009, SIP revision, the State discusses its evaluation of sources of $PM_{2.5}$ and its precursors within the Tennessee portion of the Area and its determination that these sources were meeting Subpart 1 RACM levels of emissions control. As discussed above, a State must show that all Subpart 1 RACM (including RACT for stationary sources) necessary to demonstrate attainment as expeditiously as practicable have been adopted and must consider the cumulative impact of implementing available measures to determine whether a particular emission reduction measure or set of measures is required to be adopted as RACM. Potential measures that are reasonably available considering technical and economic feasibility must be adopted as RACM if, considered collectively, they would advance the attainment date by one year or more. Because the attainment demonstration in Tennessee's attainment plan SIP revision showed attainment of the 1997 $PM_{2.5}$ NAAQS in the Chattanooga TN-GA-AL Area by the end of 2009, only measures that would advance the attainment date to the end of 2008 would be considered as Subpart 1 RACM.[7]

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[4] Pursuant to 40 CFR 56.5(b), the EPA Region 4 Regional Administrator signed a memorandum on July 20, 2015, seeking concurrence from the Director of EPA's Air Quality Policy Division (AQPD) in the Office of Air Quality Planning and Standards to act inconsistent with EPA's interpretation of CAA sections 107(d)(3)(E) and 172(c)(1) when taking action on pending and future redesignation requests in Kentucky and Tennessee because the Region is bound by the Sixth Circuit's decision in *Sierra Club* v. *EPA*. The AQPD Director issued her concurrence on July 22, 2015. The July 20, 2015, memorandum with AQPD concurrence is located in the docket for today's proposed actions.

[5] On September 3, 2015, the Sixth Circuit denied the petitions for rehearing en banc of this portion of its opinion that were filed by EPA, the state of Ohio, and industry groups from Ohio. *Sierra Club* v. *EPA,* Nos. 12–3169, 12–3182, 12–3420, Doc. 136–1 (6th Cir. Sept. 3, 2015).

[6] Subpart 1 RACM requirements at 40 CFR 51.1010 were not at issue in the D.C. Circuit's remand of the $PM_{2.5}$ implementation rule in the January 2013 *Natural Resources Defense Council* v. *EPA* decision and are therefore not subject to the Court's remand. *Cf. NRDC* v. *EPA,* 571 F.3d 1245, 1252–53 (D.C. Cir. 2009) (upholding a substantially similar interpretation of Subpart 1 RACM in the context of ozone implementation regulations).

[7] As noted in the preamble to the $PM_{2.5}$ Implementation Rule, if a ''State could not achieve significant emissions reductions by the beginning of 2008 due to time needed to implement reasonable measures or other factors, then it could be concluded that reasonably available local measures would not advance the attainment date.'' *See* 72 FR 20617.

Based on the emissions inventory and other information, the State identified the categories of sources that should be evaluated for controls. These categories include permitted stationary sources; gasoline dispensing facilities; on-road mobile sources; non-road and stationary internal combustion engines; open burning; and home heating with wood.

With regard to permitted stationary sources, Tennessee noted that conservative sensitivity modeling, conducted by the Georgia Institute of Technology, showed that completely eliminating emissions of $PM_{2.5}$, nitrogen oxides, and sulfur dioxide from non-utility point sources in the Tennessee portion of the Area would result in only small reductions in $PM_{2.5}$ concentrations (0.06 $\mu g/m^3$ to 0.25 $\mu g/m^3$). Nevertheless, Tennessee performed a detailed analysis of each major source operating in the State's portion of the Area and determined that RACT levels of emission control were already in place.[8] This analysis, and the results of sensitivity modeling, indicated that no additional reductions were available from local permitted stationary sources that would result in attainment in 2008 rather than 2009. For gasoline dispensing facilities, Tennessee deemed the use of Stage 1 vapor recovery to be the RACT level of emissions control. Tennessee stated that the existing federally-approved inspection and maintenance program constitutes RACM for on-road mobile sources and that non-road mobile sources and stationary internal combustion engines are regulated by Federal rules. Regarding open burning, Chattanooga's federally-approved local implementation plan requires open burning permits, bans open burning from May 1 through September 30, and prohibits the burning of brush cleared for road building and trash in the Tennessee portion of the Area. The State also determined that only 712 households (0.6 percent of the total households in the Tennessee portion of the Area) were heating primarily with wood and that accelerated replacement of older wood burning stoves would not advance the attainment date given the ''small portion of households using wood hearing, the mild local climate, and the normal purchases of Subpart AAA compliant wood burning stoves in the nonattainment area.''

Through this evaluation, Tennessee determined that, for each category of potential measures, there were either no additional emission reductions that could be achieved or no emission reduction measures that could be practicably implemented in time to advance attainment to the end of 2008. EPA has reviewed the RACM portion of Tennessee's October 15, 2009, attainment plan SIP revision and agrees with the State's conclusion that no additional emissions reductions were available from local sources that would have advanced the projected 2009 attainment date.

[8] See Appendix 12 of the SIP submittal for a detailed discussion of the State's analysis.

IV. Why is EPA supplementing its proposed redesignation of the area?

EPA's March 11, 2015, proposal to approve Tennessee's redesignation request for the Tennessee portion of the Area was based, in part, on the Agency's longstanding interpretation that Subpart 1 RACM need not be approved into a SIP before redesignation to attainment if the subject area is attaining the NAAQS. *See* 80 FR 16331. Although EPA disagrees with the portion of the Sixth Circuit's opinion in *Sierra Club* v. *EPA* that is inconsistent with this interpretation, the Agency is bound by this decision within the Court's jurisdiction unless it is overturned and must first approve Subpart 1 RACM into Tennessee's SIP before it can redesignate the Chattanooga TN-GA-AL Area to attainment. Therefore, EPA is supplementing its redesignation proposal to now rely on approval of the RACM portion of the State's October 15, 2009, attainment plan SIP revision.

V. Proposed Actions

EPA has reviewed the RACM portion of Tennessee's October 15, 2009, attainment plan SIP revision and proposes to approve it on the basis that it is consistent with the CAA, the CAA's implementing regulations, and EPA guidance for attainment demonstration submittals. EPA is also supplementing its March 27, 2015, proposed approval of the State's November 13, 2014, redesignation request for the Tennessee portion of the Chattanooga TN-GA-AL Area by proposing that approval of the RACM portion of the aforementioned SIP revision satisfies the Subpart 1 RACM requirement in accordance with section 107(d)(3)(E) of the CAA. Today's proposed actions are focused solely on addressing the Sixth Circuit's decision in *Sierra Club* v. *EPA* and do not reopen any other aspect of the March 27, 2015, proposal for comment.

V. Statutory and Executive Order Reviews

Under the CAA, the Administrator is required to approve a SIP submission that complies with the provisions of the Act and applicable Federal regulations. *See* 42 U.S.C. 7410(k); 40 CFR 52.02(a). Thus, in reviewing SIP submissions, EPA's role is to approve state choices, provided that they meet the criteria of the CAA. Accordingly, this action merely proposes to approve state law as meeting Federal requirements and does not impose additional requirements beyond those imposed by state law. For that reason, this action:

- Is not a significant regulatory action subject to review by the Office of Management and Budget under Executive Orders 12866 (58 FR 51735, October 4, 1993) and 13563 (76 FR 3821, January 21, 2011);
- does not impose an information collection burden under the provisions of the Paperwork Reduction Act (44 U.S.C. 3501 *et seq.*);
- is certified as not having a significant economic impact on a substantial number of small entities under the Regulatory Flexibility Act (5 U.S.C. 601 *et seq.*);
- does not contain any unfunded mandate or significantly or uniquely affect small governments, as described in the Unfunded Mandates Reform Act of 1995 (Pub. L. 104–4);
- does not have Federalism implications as specified in Executive Order 13132 (64 FR 43255, August 10, 1999);
- is not an economically significant regulatory action based on health or safety risks subject to Executive Order 13045 (62 FR 19885, April 23, 1997);
- is not a significant regulatory action subject to Executive Order 13211 (66 FR 28355, May 22, 2001);
- is not subject to requirements of Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (15 U.S.C. 272 note) because application of those requirements would be inconsistent with the CAA; and
- does not provide EPA with the discretionary authority to address, as appropriate, disproportionate human health or environmental effects, using practicable and legally permissible methods, under Executive Order 12898 (59 FR 7629, February 16, 1994).

The SIP is not approved to apply on any Indian reservation land or in any other area where EPA or an Indian tribe has demonstrated that a tribe has jurisdiction. In those areas of Indian country, the rule does not have tribal implications as specified by Executive Order 13175 (65 FR 67249, November 9, 2000), nor will it impose substantial direct costs on tribal governments or preempt tribal law.

List of Subjects in 40 CFR Part 52

Environmental protection, Air pollution control, Incorporation by reference, Intergovernmental relations, Nitrogen dioxide, Particulate matter, Reporting and recordkeeping requirements, Sulfur oxides.

Authority: 42 U.S.C. 7401 *et seq.*

Dated: September 9, 2015.

Heather McTeer Toney,

Regional Administrator, Region 4.

[FR Doc. 2015–23382 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 62

[EPA–R07–OAR–2015–0514; FRL–9933–96–Region 7]

Approval and Promulgation of Air Quality Implementation Plans for Designated Facilities and Pollutants; Missouri; Sewage Sludge Incinerators

AGENCY: Environmental Protection Agency.

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing to approve revisions to the state plan for designated facilities and pollutants developed under sections 111(d) and 129 of the Clean Air Act for the State of Missouri. This proposed action will amend the state plan to include a new plan and associated rule implementing the emissions guidelines for Commercial and Industrial Solid Waste Incineration (CISWI) Units.

DATES: Comments on this proposed action must be received in writing by October 19, 2015.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–R07–OAR–2015–0514, by mail to Paula Higbee, Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219. Comments may also be submitted electronically or through hand delivery/courier by following the detailed instructions in the **ADDRESSES** section of the direct final rule located in the rules section of this **Federal Register**.

FOR FURTHER INFORMATION CONTACT: Paula Higbee, Environmental Protection Agency, Air Planning and Development Branch, 11201 Renner Boulevard, Lenexa, Kansas 66219 at 913–551–7028 or by email at *higbee.paula@epa.gov.*

SUPPLEMENTARY INFORMATION: In the final rules section of this **Federal Register**, EPA is approving the state's SIP revision as a direct final rule without prior proposal because the Agency views this as a noncontroversial revision amendment and anticipates no relevant adverse comments to this action. A detailed rationale for the approval is set forth in the direct final rule. If no relevant adverse comments are received in response to this action, no further activity is contemplated in relation to this action. If EPA receives relevant adverse comments, the direct final rule will be withdrawn and all public comments received will be addressed in a subsequent final rule based on this proposed action. EPA will not institute a second comment period on this action. Any parties interested in commenting on this action should do so at this time. Please note that if EPA receives adverse comment on part of this rule and if that part can be severed from the remainder of the rule, EPA may adopt as final those parts of the rule that are not the subject of an adverse comment. For additional information, see the direct final rule which is located in the rules section of this **Federal Register**.

List of Subjects in 40 CFR Part 62

Environmental protection, Administrative practice and procedure, Air pollution control, Commercial and industrial solid waste incinerators, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: September 3, 2015.

Becky Weber,

Acting Regional Administrator, Region 7.

[FR Doc. 2015–23384 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 15, 73, and 74

[MB Docket No. 15–146; GN Docket No. 12–268; DA 15–918]

Preserving Vacant Channels in the UHF Television Band for Unlicensed Use

AGENCY: Federal Communications Commission.

ACTION: Proposed rule.

SUMMARY: In this document, the Media Bureau of the Federal Communications Commission (Commission) provides notice of the revised comment and reply comment deadlines in this proceeding. The comment period in this proceeding has previously been suspended pending action in the Commission's incentive auction proceeding and the Media Bureau announces that it has been restarted and the new deadlines for filing comments and reply comments.

DATES: Comments Due: September 30, 2015. Reply Comments Due: October 30, 2015.

ADDRESSES: You may submit comments, identified by MB Docket No. 15–146 and GN Docket No. 12–268, by any of the following methods:

- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Federal Communications Commission's Web site: http://www.fcc.gov/cgb/ecfs/.* Follow the instructions for submitting comments.
- *Mail:* Filings can be sent by hand or messenger delivery, by commercial overnight courier, or by first-class or overnight U.S. Postal Service mail (although we continue to experience delays in receiving U.S. Postal Service mail.) All filings must be addressed to the Commission's Secretary, Office of the Secretary, Federal Communications Commission.
- *People with Disabilities:* Contact the FCC to request reasonable accommodations (accessible format documents, sign language interpreters, CART, etc.) by email: *FCC504@fcc.gov* or phone: 202–418–0530 or TTY: 202–418–0432.

FOR FURTHER INFORMATION CONTACT: Shaun Maher, *Shaun.Maher@fcc.gov* of the Media Bureau, Video Division, (202) 418–2324, and Paul Murray, *Paul.Murray@fcc.gov* of the Office of Engineering and Technology, (202) 418–0688.

SUPPLEMENTARY INFORMATION: This is a summary of the Media Bureau's Order, DA 15–918, adopted August 12, 2015, in MB Docket No. 15–146 (Order). The full text of the Order is available for inspection and copying during regular business hours in the FCC Reference Center, 445 12th Street SW., Room CY–A257, Portals II, Washington, DC 20554. This document is available in alternative formats (computer diskette, large print, audio record, and Braille). Persons with disabilities who need documents in these formats may contact the FCC by email: *FCC504@fcc.gov* or phone: 202–418–0530 or TTY: 202–418–0432.

Synopsis

1. On June 16, 2015, the Commission released a Notice of Proposed Rulemaking, 30 FCC Rcd 6711 (2015) in MB Docket No. 15–146 (Vacant Channel NPRM) seeking comment on rules to preserve vacant television channels for shared use by white space devices and wireless microphones. On July 29, 2015, the Media Bureau, in an Order, DA 15–867, on delegated authority, suspended the comment and reply comment

deadlines in this proceeding until further notice.

2. In its document, FCC 15–78, released August 11, 2015 (Auctions Procedures PN), the Commission adopted its proposal to allow the optimization tool to assign television stations within the 600 MHz Band where necessary to accommodate market variation in a manner that best fulfills the clearing target objectives, and not to restrict it to assignments in specific portions of the 600 MHz Band, including the duplex gap. To mitigate the potential impact on white space devices and wireless microphones in areas where the duplex gap is subject to impairment, the Commission tentatively concluded that it will designate a second available television channel in the remaining television band in such areas for shared use by white space devices and wireless microphones, in addition to the one such channel it has tentatively concluded will be made available in each area of the United States for shared use by these devices and microphones. The Commission invited comment on this tentative conclusion and stated that it intends to address in the same order all proposals in the Vacant Channel NPRM as well as the proposals raised in the Auctions Procedures PN. To that end, the Commission directed the Media Bureau to establish new comment and reply deadlines of September 30 and October 30, 2015, respectively, for the proposals in the Vacant Channel NPRM as well as the proposal in paragraph 32 of the Auctions Procedures PN.

3. By this Order, as directed by the Commission in the Auctions Procedures PN, the Media Bureau announces that comments are now due on September 30, 2015 and reply comments on October 30, 2015.

Kevin Harding,

Associate Chief, Video Division, Media Bureau.

[FR Doc. 2015–23380 Filed 9–17–15; 8:45 am]

BILLING CODE 6712–01–P

DEPARTMENT OF THE INTERIOR

Fish and Wildlife Service

50 CFR Part 17

[4500030115]

Endangered and Threatened Wildlife and Plants; 90-Day Findings on 25 Petitions

AGENCY: Fish and Wildlife Service, Interior.

ACTION: Notice of petition findings and initiation of status reviews.

SUMMARY: We, the U.S. Fish and Wildlife Service (Service), announce 90-day findings on various petitions to list, reclassify, or delist fish, wildlife, or plants under the Endangered Species Act of 1973, as amended (Act). Based on our review, we find that two petitions do not present substantial scientific or commercial information indicating that the petitioned actions may be warranted, and we are not initiating status reviews in response to these petitions. We refer to these as ''not-substantial petition findings.''

We also find that 23 petitions present substantial scientific or commercial information indicating that the petitioned actions may be warranted. Therefore, with the publication of this notice, we are initiating a review of the status of these species to determine if the petitioned actions are warranted. To ensure that these status reviews are comprehensive, we are requesting scientific and commercial data and other information regarding these species. Based on the status reviews, we will issue 12-month findings on the petitions, which will address whether the petitioned action is warranted, as provided in section 4(b)(3)(B) of the Act.

DATES: To allow us adequate time to conduct the status reviews, we request that we receive information no later than November 17, 2015. Information submitted electronically using the Federal eRulemaking Portal (see **ADDRESSES**, below) must be received by 11:59 p.m. Eastern Time on the closing date.

ADDRESSES: *Not-substantial petition findings:* The not-substantial petition findings announced in this document are available on *http://www.regulations.gov* under the appropriate docket number (see Table 2, below). Supporting information in preparing these findings is available for public inspection, by appointment, during normal business hours by contacting the appropriate person, as specified under **FOR FURTHER INFORMATION CONTACT**.

Status reviews: You may submit information on species for which a status review is being initiated by one of the following methods:

(1) *Electronically:* Go to the Federal eRulemaking Portal: *http://www.regulations.gov.* In the Search box, enter the appropriate docket number (see Table 1, below). You may submit information by clicking on ''Comment Now!'' If your information will fit in the provided comment box, please use this feature of *http://www.regulations.gov,* as it is most compatible with our information review procedures. If you attach your information as a separate document, our preferred file format is Microsoft Word. If you attach multiple comments (such as form letters), our preferred format is a spreadsheet in Microsoft Excel.

(2) *By hard* copy: Submit by U.S. mail or hand-delivery to: Public Comments Processing, Attn: [Insert appropriate docket number; see Table 1, below]; U.S. Fish and Wildlife Service, MS: BPHC, 5275 Leesburg Pike; Falls Church, VA 22041–3803.

We request that you send information only by the methods described above. We will post all information received on *http://www.regulations.gov.* This generally means that we will post any personal information you provide us (see Request for Information for Status Reviews, below, for more details).

TABLE 1—LIST OF SUBSTANTIAL FINDINGS FOR WHICH A STATUS REVIEW IS BEING INITIATED

Common name	Docket No.	URL to docket in regs.gov
Blue Calamintha bee	FWS–R4–ES–2015–0077	*http://www.regulations.gov/#!docketDetail;D=FWS-R4-ES-2015-0077.*
California spotted owl	FWS–R8–ES–2015–0139	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0139.*
Cascade torrent salamander	FWS–R1–ES–2015–0080	*http://www.regulations.gov/#!docketDetail;D=FWS-R1-ES-2015-0080.*
Columbia torrent salamander	FWS–R1–ES–2015–0083	*http://www.regulations.gov/#!docketDetail;D=FWS-R1-ES-2015-0083.*
Florida pine snake	FWS–R4–ES–2015–0086	*http://www.regulations.gov/#!docketDetail;D=FWS-R4-ES-2015-0086.*
Inyo Mountains salamander	FWS–R8–ES–2015–0092	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0092.*
Kern Plateau salamander	FWS–R8–ES–2015–0093	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0093.*
Lesser slender salamander	FWS–R8–ES–2015–0097	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0097.*
Limestone salamander	FWS–R8–ES–2015–0099	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0099.*
Northern bog lemming	FWS–R5–ES–2015–0103	*http://www.regulations.gov/#!docketDetail;D=FWS-R5-ES-2015-0103.*
Panamint alligator lizard	FWS–R8–ES–2015–0105	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0105.*

TABLE 1—LIST OF SUBSTANTIAL FINDINGS FOR WHICH A STATUS REVIEW IS BEING INITIATED—Continued

Common name	Docket No.	URL to docket in regs.gov
Peaks of Otter salamander	FWS–R5–ES–2015–0106	*http://www.regulations.gov/#!docketDetail;D=FWS-R5-ES-2015-0106.*
Regal fritillary	FWS–R6–ES–2015–0078	*http://www.regulations.gov/#!docketDetail;D=FWS-R6-ES-2015-0078.*
Rusty patched bumble bee	FWS–R3–ES–2015–0112	*http://www.regulations.gov/#!docketDetail;D=FWS-R3-ES-2015-0112.*
Shasta salamander	FWS–R8–ES–2015–0115	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0115.*
Short-tailed snake	FWS–R4–ES–2015–0116	*http://www.regulations.gov/#!docketDetail;D=FWS-R4-ES-2015-0116.*
Southern rubber boa	FWS–R8–ES–2015–0119	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0119.*
Tinian monarch	FWS–R1–ES–2015–0118	*http://www.regulations.gov/#!docketDetail;D=FWS-R1-ES-2015-0118.*
Tricolored blackbird	FWS–R8–ES–2015–0138	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0138.*
Tufted puffin	FWS–R1–ES–2015–0108	*http://www.regulations.gov/#!docketDetail;D=FWS-R1-ES-2015-0108.*
Virgin River spinedace	FWS–R6–ES–2015–0121	*http://www.regulations.gov/#!docketDetail;D=FWS-R6-ES-2015-0121.*
Wood turtle	FWS–R5–ES–2015–0122	*http://www.regulations.gov/#!docketDetail;D=FWS-R5-ES-2015-0122.*
Yuman desert fringe-toed lizard	FWS–R2–ES–2015–0124	*http://www.regulations.gov/#!docketDetail;D=FWS-R2-ES-2015-0124.*

TABLE 2—LIST OF NOT SUBSTANTIAL FINDINGS

Common name	Docket No.	URL to docket in regs.gov
Cahaba pebblesnail	FWS–R4–ES–2015–0079	*http://www.regulations.gov/#!docketDetail;D=FWS-R4-ES-2015-0079.*
Stephens' kangaroo rat	FWS–R8–ES–2015–0140	*http://www.regulations.gov/#!docketDetail;D=FWS-R8-ES-2015-0140.*

FOR FURTHER INFORMATION CONTACT:

Common name	Contact person
Blue Calamintha bee	Andreas Moshogianis, 404–679–7119.
Cahaba pebblesnail	Robert Tawes, 404–679–7142.
California spotted owl	Scott Flaherty, 916–978–6156.
Cascade torrent salamander	Paul Henson, 503–231–6179.
Columbia torrent salamander	Eric Rickerson, 360 753–9440.
Florida pine snake	Andreas Moshogianis, 404–679–7119.
Inyo Mountains salamander	Ted Koch, 775–861–6300.
Kern Plateau salamander	Jennifer Norris, 916–414–6600.
Lesser slender salamander	Steven Henry, 805–644–1766.
Limestone salamander	Jennifer Norris, 916–414–6600.
Northern bog lemming	Krishna Gifford, 413–253–8619.
Panamint alligator lizard	Mendel Stewart, 760–431–9440.
Peaks of Otter salamander	Roberta Hylton, 276–623–1233, ext. 22.
Regal fritillary	Justin Shoemaker, 309–757–5800, ext. 214.
Rusty patched bumble bee	Laura Ragan, 612–713–5157.
Shasta salamander	Jennifer Norris, 916–414–6600.
Short-tailed snake	Andreas Moshogianis, 404–679–7119.
Southern rubber boa	Mendel Stewart, 760–431–9440.
Stephens' kangaroo rat	Bradd Bridges, 760–431–9440, ext. 221.
Tinian monarch	Kristi Young, 808–792–9400.
Tricolored blackbird	Jennifer Norris, 916–414–6600.
Tufted puffin	Eric Rickerson, 360 753–9440.
Virgin River spinedace	Justin Shoemaker, 309–757–5800, ext. 214.
Wood turtle	Wende Mahaney, 207–866–3344.
Yuman desert fringe-toed lizard	Michelle Shaughnessy, 505–248–6920.

If you use a telecommunications device for the deaf (TDD), please call the Federal Information Relay Service (FIRS) at 800–877–8339.

SUPPLEMENTARY INFORMATION:

Request for Information for Status Reviews

When we make a finding that a petition presents substantial information indicating that listing, reclassification, or delisting a species may be warranted, we are required to promptly review the status of the species (status review). For the status review to be complete and based on the best available scientific and commercial information, we request information on these species from governmental agencies, Native American Tribes, the scientific community, industry, and any other interested parties. We seek information on:

(1) The species' biology, range, and population trends, including:

(a) Habitat requirements;

(b) Genetics and taxonomy;

(c) Historical and current range, including distribution patterns;

(d) Historical and current population levels, and current and projected trends; and

(e) Past and ongoing conservation measures for the species, its habitat, or both.

(2) The factors that are the basis for making a listing, reclassification, or delisting determination for a species under section 4(a) of the Act (16 U.S.C. 1531 *et seq.*), which are:

(a) The present or threatened destruction, modification, or curtailment of its habitat or range (Factor A);

(b) Overutilization for commercial, recreational, scientific, or educational purposes (Factor B);

(c) Disease or predation (Factor C);

(d) The inadequacy of existing regulatory mechanisms (Factor D); or

(e) Other natural or manmade factors affecting its continued existence (Factor E).

(3) The potential effects of climate change on the species and its habitat.

If, after the status review, we determine that listing is warranted, we will propose critical habitat (see definition in section 3(5)(A) of the Act) for domestic (U.S.) species under section 4 of the Act, to the maximum extent prudent and determinable at the time we propose to list the species. Therefore, we also request data and information for the species listed in *Table 1* on:

(1) What may constitute ''physical or biological features essential to the conservation of the species,'' within the geographical range occupied by the species;

(2) Where these features are currently found;

(3) Whether any of these features may require special management considerations or protection;

(4) Specific areas outside the geographical area occupied by the species that are ''essential for the conservation of the species''; and

(5) What, if any, critical habitat you think we should propose for designation if the species is proposed for listing, and why such habitat meets the requirements of section 4 of the Act.

Please include sufficient information with your submission (such as scientific journal articles or other publications) to allow us to verify any scientific or commercial information you include.

Submissions merely stating support for or opposition to the actions under consideration without providing supporting information, although noted, will not be considered in making a determination. Section 4(b)(1)(A) of the Act directs that determinations as to whether any species is an endangered or threatened species must be made ''solely on the basis of the best scientific and commercial data available.''

You may submit your information concerning these status reviews by one of the methods listed in the **ADDRESSES** section. If you submit information via *http://www.regulations.gov,* your entire submission—including any personal identifying information—will be posted on the Web site. If you submit a hardcopy that includes personal identifying information, you may request at the top of your document that we withhold this personal identifying information from public review. However, we cannot guarantee that we will be able to do so. We will post all hardcopy submissions on *http://www.regulations.gov*.

Information and supporting documentation that we received and used in preparing these 90-day findings is available for you to review at *http://www.regulations.gov,* or you may make an appointment during normal business hours at the appropriate lead U.S. Fish and Wildlife Service Field Office (contact the person listed under **FOR FURTHER INFORMATION CONTACT**).

Background

Section 4(b)(3)(A) of the Act requires that we make a finding on whether a petition to list, delist, or reclassify a species presents substantial scientific or commercial information indicating that the petitioned action may be warranted. To the maximum extent practicable, we are to make this finding within 90 days of our receipt of the petition and publish our notice of the finding promptly in the **Federal Register**.

Our standard for substantial scientific or commercial information within the Code of Federal Regulations (CFR) with regard to a 90-day petition finding is ''that amount of information that would lead a reasonable person to believe that the measure proposed in the petition may be warranted'' (50 CFR 424.14(b)). If we find that substantial scientific or commercial information was presented, we are required to promptly commence a review of the status of the species, which will be subsequently summarized in our 12-month finding.

Section 4 of the Act (16 U.S.C. 1533) and its implementing regulations at 50 CFR 424 set forth the procedures for adding a species to, or removing a species from, the Federal Lists of Endangered and Threatened Wildlife and Plants. A species may be determined to be an endangered or threatened species due to one or more of the five factors described in section 4(a)(1) of the Act (see Request for Information for Status Reviews, above).

In considering what factors might constitute threats, we must look beyond the exposure of the species to a factor to evaluate whether the species may respond to the factor in a way that causes actual impacts to the species. If there is exposure to a factor and the species responds negatively, the factor may be a threat and, during the subsequent status review, we attempt to determine how significant a threat it is. The threat is significant if it drives, or contributes to, the risk of extinction of the species such that the species may warrant listing as endangered or threatened as those terms are defined in the Act. However, the identification of factors that could affect a species negatively may not be sufficient to compel a finding that the information in the petition and our files is substantial. The information must include evidence sufficient to suggest that these factors may be operative threats that act on the species to the point that the species may meet the definition of an endangered or threatened species under the Act.

Evaluation of a Petition To List the Blue Calamintha Bee as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R4–ES–2015–0077 under the Supporting Documents section.

Species and Range

Blue Calamintha bee (*Osmia calaminthae);* Florida

Petition History

On February 5, 2015, we received a petition dated February 5, 2015, from Defenders of Wildlife requesting that the blue Calamintha bee be listed as endangered or threatened and that critical habitat be designated for this species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the blue Calamintha bee (*Osmia calaminthae*) based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Cahaba Pebblesnail as an Endangered Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R4–ES–2015–0079 under the Supporting Documents section.

Species and Range

Cahaba pebblesnail (*Clappia cahabensis*); Alabama

Petition History

On January 6, 2015, we received a petition dated December 18, 2014, from the Institute for Wildlife Protection, requesting that the Cahaba pebblesnail be listed as endangered under the Act. The petition further requested that we emergency list the species. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In a February 18, 2015, letter to the petitioner, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses the petition to list the species as endangered.

Finding

Based on our review of the petition, sources cited in the petition, and information available in our files at the time the petition was received, we find that the petition does not provide substantial scientific or commercial information indicating that listing the Cahaba pebblesnail (*Clappia cahabensis*) as endangered may be warranted. Because the petition does not present substantial information indicating that listing this species as endangered may be warranted, we are not initiating a status review in response to this petition. Our justification for this finding can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R4–ES–2015–0079 under the ''Supporting Documents'' section. However, we ask that the public submit to us any new information that becomes available concerning the status of, or threats to, the Cahaba pebblesnail or its habitat at any time (see **FOR FURTHER INFORMATION CONTACT**).

Evaluation of a Petition To List the California Spotted Owl as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0139 under the Supporting Documents section.

Species and Range

California spotted owl (*Strix occidentalis occidentalis*); California

Petition History

On January 9, 2015, we received a petition dated December 22, 2014, from the Wild Nature Institute and the John Muir Project of the Earth Island Institute, requesting that the California spotted owl be listed as endangered or threatened and that we designate critical habitat under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In a February 12, 2015, letter to the petitioners, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses this petition.

Finding

Based on our review of the petitions and sources cited in the petitions, we find that the petitions present substantial scientific or commercial information indicating that the petitioned action may be warranted for the California spotted owl (*Strix occidentalis occidentalis*) based on Factors A, D, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Second Petition To List the California Spotted Owl

We received another petition dated August 19, 2015, from Sierra Forest Legacy and Defenders of Wildlife, to list the California spotted owl as endangered, and requesting we designate critical habitat for the species. This finding serves to notify the petitioners that we have received their petition, and that, because we have made a substantial finding on the December 22, 2014, petition and are initiating a status review of the species, we will include the information they provided in our status review for the owl.

Evaluation of a Petition To List the Cascade Torrent Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R1–ES–2015–0080 under the Supporting Documents section.

Species and Range

Cascade torrent salamander (*Rhyacotriton cascadae*); Washington and Oregon

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Cascade torrent salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the Cascade torrent salamander (*Rhyacotriton cascadae*) as endangered or threatened may be warranted based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Columbia Torrent Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R1–ES–2015–0083 under the Supporting Documents section.

Species and Range

Columbia torrent salamander (*Rhyacotriton kezeri*); Oregon and Washington

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 amphibians and reptiles, including the Columbia torrent salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the

Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the Columbia torrent salamander (*Rhyacotriton kezeri*) as endangered or threatened may be warranted based on Factor A. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factor identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Florida Pine Snake as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R4–ES–2015–0086 under the Supporting Documents section.

Species and Range

Florida pine snake (*Pituophis melanoleucus mugitus);* Alabama, Florida, Georgia, South Carolina

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Florida pine snake, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Florida pine snake (*Pituophis melanoleucus mugitus*) for listing based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Inyo Mountains Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0092 under the Supporting Documents section.

Species and Range

Inyo Mountains salamander (*Batrachoseps campi*); California.

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Inyo Mountains salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Inyo Mountains salamander (*Batrachoseps campi*) based on Factor A. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factor identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Kern Plateau Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R8–ES–2015–0093 under the Supporting Documents section.

Species and Range

Kern Plateau salamander (*Batrachoseps robustus*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Kern Plateau salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Kern Plateau salamander (*Batrachoseps robustus*) based on Factor A. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factor identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Lesser Slender Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R8–ES–2015–0097 under the Supporting Documents section.

Species and Range

Lesser slender salamander (*Batrachoseps minor*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the lesser slender salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the lesser slender salamander (*Batrachoseps minor*) based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Limestone Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R8–ES–2015–0099 under the Supporting Documents section.

Species and Range

Limestone salamander (*Hydromantes brunus*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the limestone salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the limestone salamander (*Hydromantes brunus*) based on Factor A. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factor identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Northern Bog Lemming as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R5–ES–2015–0103 under the Supporting Documents section.

Species and Range

Northern bog lemming (*Synaptomys borealis*); Alaska, Washington, Idaho, Maine, Montana, Minnesota, New Hampshire, and New York

Petition History

On September 30, 2014, we received a petition dated September 29, 2014, from WildEarth Guardians requesting that the northern bog lemming be listed as endangered or threatened and that critical habitat be designated for this species under the Act. The petitioner requested:

- Listing of the full species;
- Listing of the individual subspecies (in particular, the disjunct population of *S. b. sphagnicola* south of the St. Lawrence River in Maine and New Hampshire); or
- Listing of the U.S. distinct population segment (DPS) of *S. b. chapmani.*

The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In an October 3, 2014, letter to the petitioner, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the northern bog lemming (*Synaptomys borealis*) based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Panamint Alligator Lizard as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R8–ES–2015–0105 under the Supporting Documents section.

Species and Range

Panamint alligator lizard (*Elgaria panamintina*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Panamint alligator lizard, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Panamint alligator lizard (*Elgaria panamintina*) based on Factors A and B. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Peaks of Otter Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at http://*www.regulations.gov* under Docket No. FWS–R5–ES–2015–0106 under the Supporting Documents section.

Species and Range

Peaks of Otter salamander (*Plethodon hubrichti*); Virginia

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Peaks of Otter salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Peaks of Otter salamander (*Plethodon hubrichti*) based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Regal Fritillary as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R6–ES–2015–0078 under the Supporting Documents section.

Species and Range

Regal fritillary (*Speyeria idalia*); Kansas, Arkansas, North Carolina, Missouri, Nebraska, Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island, New York, Pennsylvania, New Jersey, Delaware, Maryland, Virginia, and West Virginia

Petition History

On April 24, 2013, we received a petition dated April 19, 2013, from WildEarth Guardians, requesting that the regal fritillary be listed as endangered or threatened under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the regal fritillary (*Speyeria idalia*) based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Rusty Patched Bumble Bee as an Endangered Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R3–ES–2015–0112 under the Supporting Documents section.

Species and Range

Rusty patched bumble bee (*Bombus affinis*); Maine, New Hampshire, Vermont, Massachusetts, Rhode Island, Connecticut, New York, Pennsylvania, Delaware, Maryland, Virginia, West Virginia, North Carolina, South Carolina, Tennessee, Ohio, Kentucky, Indiana, Illinois, Iowa, Michigan, Wisconsin, Minnesota, North Dakota, South Dakota, and Ontario, Canada

Petition History

On February 5, 2013, the U.S. Fish and Wildlife Service received a petition dated January 31, 2013, from the Xerces Society for Invertebrate Conservation (Xerces) requesting that the rusty patched bumble bee be listed under the Act as an endangered species. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). On February 14, 2014, Xerces provided the Service with written notice of their intent to sue for failure to issue a petition finding. Xerces filed a complaint on May 13, 2014, against the Service for failure to issue a timely 90-day finding. The Service and Xerces reached a settlement to deliver a 90-day petition finding to the **Federal Register** no later than September 30, 2015. This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the rusty patched bumble bee (*Bombus affinis*) based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Shasta Salamander as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0115 under the Supporting Documents section.

Species and Range

Shasta salamander (*Hydromantes shastae*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Shasta salamander, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the Shasta salamander (*Hydromantes shastae*) as endangered or threatened may be warranted based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Short-Tailed Snake as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R4–ES–2015–0116 under the Supporting Documents section.

Species and Range

Short-tailed snake (*Stilosoma extenuatum*); Florida

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the short-tailed snake, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the short-tailed snake (*Stilosoma extenuatum*) as endangered or threatened may be warranted based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Southern Rubber Boa as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0119 under the Supporting Documents section.

Species and Range

Southern rubber boa (*Charina umbratica* or *Charina bottae umbratica*); California

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the southern rubber boa, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the southern rubber boa (*Charina umbratica* or *Charina bottae umbratica*) as endangered or threatened may be warranted based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To Remove the Stephens' Kangaroo Rat From the Federal List of Endangered and Threatened Wildlife

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0140 under the Supporting Documents section.

Species and Range

Stephens' kangaroo rat (*Dipodomys stephensi*); California

Petition History

On November 10, 2014, we received a petition dated November 7, 2014, from the Riverside County Farm Bureau and the Center for Environmental Science, Accuracy and Responsibility, requesting that Stephens' kangaroo rat, which is listed as an endangered species, be removed from the Federal List of Endangered and Threatened Wildlife (''delisted''), based on a new analysis of the rat's dispersal ability. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition does not present substantial scientific or commercial information indicating that the petitioned action may be warranted for the Stephens' kangaroo rat (*Dipodomys stephensi*). Because the petition does not present substantial information indicating that delisting the Stephens' kangaroo rat may be warranted, we are not initiating a status review in response to this petition. Our justification for this finding can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0140 under the ''Supporting Documents'' section. However, we ask that the public submit to us any new information that becomes available concerning the status of, or threats to, this species or its habitat at any time (see **FOR FURTHER INFORMATION CONTACT**).

Evaluation of a Petition To List the Tinian Monarch as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R1–ES–2015–0118 under the Supporting Documents section.

Species and Range

Tinian monarch (*Monarcha takatsukasae*); Tinian Island (an island in the Commonwealth of Northern Mariana Islands)

Petition History

On December 12, 2013, we received a petition dated December 11, 2013, from the Center for Biological Diversity, requesting that the Tinian monarch be listed as endangered or threatened under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In a January 29, 2014, letter to the petitioner, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Tinian monarch (*Monarcha takatsukasae*) based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Tricolored Blackbird as an Endangered Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R8–ES–2015–0138 under the Supporting Documents section.

Species and Range

Tricolored blackbird (*Agelaius tricolor*); California, Oregon, Nevada, Washington (United States), and Baja California (Mexico)

Petition History

On February 5, 2015, we received a petition dated February 3, 2015, from the Center for Biological Diversity, requesting that the tricolored blackbird be listed as endangered under the Act. The petitioner also requested that critical habitat be designated for this species. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In a March 13, 2015, letter to the petitioner, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the tricolored blackbird (*Agelaius tricolor*) based on Factors A, C, D, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for the tricolored blackbird, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the U.S. Distinct Population Segment (DPS) of Tufted Puffin as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R1–ES–2015–0108 under the Supporting Documents section.

Species and Range

Contiguous U.S. DPS of tufted puffin (*Fratercula cirrhata*); Washington, Oregon, California

Petition History

On February 14, 2014, we received a petition dated February 12, 2014, from Natural Resources Defense Council, requesting that the contiguous U.S. DPS of the tufted puffin be listed as endangered or threatened and that critical habitat be designated for this species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the contiguous U.S. DPS of tufted puffin (*Fratercula cirrhata*) based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Virgin River Spinedace as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R6–ES–2015–0121 under the Supporting Documents section.

Species and Range

Virgin River spinedace (*Lepidomeda mollispinis mollispinis*); Arizona, Nevada, and Utah

Petition History

On November 20, 2012, we received a petition dated November 20, 2012, from the Center for Biological Diversity, requesting that the Virgin River spinedace be listed as endangered or threatened under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). In a December 20, 2012, letter to the petitioner, we responded that we reviewed the information presented in the petition and did not find that the petition presented information that an emergency listing is warranted. This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that the petitioned action may be warranted for the Virgin River spinedace (*Lepidomeda mollispinis mollispinis*) based on Factors A, C, and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Wood Turtle as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://www.regulations.gov* under Docket No. FWS–R5–ES–2015–0122 under the Supporting Documents section.

Species and Range

Wood turtle (*Glyptemys insculpta*); Connecticut, Delaware, Iowa, Maine, Maryland, Massachusetts, Michigan, Minnesota, New Hampshire, New Jersey, New York, Ohio, Pennsylvania, Rhode Island, Vermont, Virginia, West Virginia, Wisconsin, and Canada

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the wood turtle, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the wood turtle (*Glyptemys insculpta*) as endangered or threatened may be warranted based on Factors A, B, C, D, and E. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Evaluation of a Petition To List the Yuman Desert Fringe-toed Lizard as an Endangered or Threatened Species Under the Act

Additional information regarding our review of this petition can be found as an appendix at *http://*

www.regulations.gov under Docket No. FWS–R2–ES–2015–0124 under the Supporting Documents section.

Species and Range

Yuman desert fringe-toed lizard (*Uma rufopunctata*); Arizona (United States) and Sonora (Mexico)

Petition History

On July 11, 2012, we received a petition dated July 11, 2012, from the Center for Biological Diversity, requesting that 53 species of reptiles and amphibians, including the Yuman desert fringe-toed lizard, be listed as endangered or threatened and that critical habitat be designated for these species under the Act. The petition clearly identified itself as such and included the requisite identification information for the petitioner, required at 50 CFR 424.14(a). This finding addresses the petition.

Finding

Based on our review of the petition and sources cited in the petition, we find that the petition presents substantial scientific or commercial information indicating that listing the Yuman desert fringe-toed lizard (*Uma rufopunctata*) may be warranted based on Factors A and E. However, during our status review, we will thoroughly evaluate all potential threats to the species. Thus, for this species, the Service requests information on the five listing factors under section 4(a)(1) of the Act, including the factors identified in this finding (see Request for Information for Status Reviews, above).

Conclusion

On the basis of our evaluation of the information presented under section 4(b)(3)(A) of the Act, we have determined that the petitions summarized above for the Cahaba pebblesnail and Stephens' kangaroo rat do not present substantial scientific or commercial information indicating that the requested actions may be warranted. Therefore, we are not initiating status reviews for these species.

The petitions summarized above for the blue Calamintha bee, California spotted owl, Cascade torrent salamander, Columbia torrent salamander, Florida pine snake, Inyo Mountains salamander, Kern Plateau salamander, lesser slender salamander, limestone salamander, northern bog lemming, Panamint alligator lizard, Peaks of Otter salamander, regal fritillary, rusty patched bumble bee, Shasta salamander, short-tailed snake, southern rubber boa, Tinian monarch, tricolored blackbird, tufted puffin, Virgin River spinedace, wood turtle, and the Yuman desert fringe-toed lizard present substantial scientific or commercial information indicating that the requested actions may be warranted.

Because we have found that these petitions present substantial information indicating that the petitioned actions may be warranted, we are initiating status reviews to determine whether these actions under the Act are warranted. At the conclusion of the status reviews, we will issue a 12-month finding, in accordance with section 4(b)(3)(B) of the Act, as to whether or not the Service believes listing is warranted.

It is important to note that the ''substantial information'' standard for a 90-day finding differs from the Act's ''best scientific and commercial data'' standard that applies to a status review to determine whether a petitioned action is warranted. A 90-day finding does not constitute a status review under the Act. In a 12-month finding, we will determine whether a petitioned action is warranted after we have completed a thorough status review of the species, which is conducted following a substantial 90-day finding. Because the Act's standards for 90-day and 12-month findings are different, as described above, a substantial 90-day finding does not mean that the 12-month finding will result in a warranted finding.

References Cited

A complete list of references cited is available on the Internet at *http://www.regulations.gov* and upon request from the appropriate lead field offices (contact the person listed under **FOR FURTHER INFORMATION CONTACT**).

Authors

The primary authors of this notice are staff members of the Ecological Services Program, U.S. Fish and Wildlife Service.

Authority

The authority for these actions is the Endangered Species Act of 1973, as amended (16 U.S.C. 1531 *et seq.*).

Dated: August 31, 2015.

Stephen Guertin,

Acting Director, U.S. Fish and Wildlife Service.

[FR Doc. 2015–23315 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–55–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

50 CFR Part 200

[Docket No. 150227193–5193–01]

RIN 0648–BE92

Establish a Single Small Business Size Standard for Commercial Fishing Businesses

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

ACTION: Proposed rule; request for comment.

SUMMARY: NMFS proposes to establish a small business size standard of $11 million in annual gross receipts for all businesses in the commercial fishing industry (NAICS 11411), for Regulatory Flexibility Act (RFA) compliance purposes only. The proposed $11 million standard would be used in RFA analyses in place of the U.S. Small Business Administration's (SBA) current standards of $20.5 million, $5.5 million, and $7.5 million for the finfish (NAICS 114111), shellfish (NAICS 114112), and other marine fishing (NAICS 114119) sectors of the U.S. commercial fishing industry, respectively. Establishing a single size standard of $11 million for the commercial fishing industry would simplify the RFA analyses done in support of NMFS' rules, better meet the RFA's intent by more accurately representing expected disproportionate effects of NMFS' rules between small and large businesses, create a standard that more accurately reflects the size distribution of all businesses in the commercial fishing industry, and allow NMFS to determine when changes to the standard are necessary and appropriate.

DATES: Comments must be received by October 19, 2015.

ADDRESSES: You may submit comments on this document, identified by NOAA–NMFS–2015–0061, by either of the following methods:

- *Electronic Submission:* Submit all electronic public comments via the Federal e-Rulemaking Portal. Go to *www.regulations.gov/#!docketDetail;D=NOAA-NMFS-2015-0061,* click the ''Comment Now!'' icon, complete the required fields, and enter or attach your comments.
- *Mail:* Send written comments to Mike Travis, NOAA Fisheries Service,

Southeast Regional Office, 263 13th Ave. S., St. Petersburg, FL 33701.

Instructions: Comments sent by any other method, to any other address or individual, or received after the end of the comment period, may not be considered by NMFS. All comments received are a part of the public record and will generally be posted for public viewing on *www.regulations.gov* without change. All personal identifying information (*e.g.,* name, address, etc.), confidential business information, or otherwise sensitive information submitted voluntarily by the sender will be publicly accessible. NMFS will accept anonymous comments (enter ''N/A'' in the required fields if you wish to remain anonymous), and will accept attachments to electronic comments in Microsoft Word, Excel, or Adobe PDF file formats only.

FOR FURTHER INFORMATION CONTACT: Mike Travis, Industry Economist, at (727) 209–5982.

SUPPLEMENTARY INFORMATION:

Background

Prior to 2013, SBA had set the small business size standard for all sectors of the commercial fishing industry at the same amount. Since 2005, this standard had been $4 million in annual gross receipts (revenues). Effective July 22, 2013, SBA established significantly different and higher size standards for the three separate sectors of the industry (78 FR 37398, June 20, 2013): $19 million for commercial finfish fishing businesses (NAICS 114111), $5.0 million for commercial shellfish fishing businesses (NAICS 114112), and $7.0 million for other commercial marine fishing businesses (NAICS 114119). These standards were subsequently adjusted for inflation to $20.5 million, $5.5 million, and $7.5 million, respectively, via an interim final rule, effective July 14, 2014 (79 FR 33647, June 12, 2014). The Small Business Jobs Act of 2010 requires SBA to review all size standards every five years to account for changes in industry structure and market conditions. SBA is also required to assess the impact of inflation on its monetary-based size standards at least once every five years (13 CFR 121.102). However, as reflected by the timing of the two recent rulemakings adjusting the size standards, SBA is not required to conduct the reviews for these two purposes simultaneously. Thus, these size standards are likely to change on a regular basis.

Under the RFA, an agency must prepare an initial and final regulatory flexibility analysis (IRFA/FRFA) for each proposed and final rule, respectively, unless it certifies that a rule will not have a significant economic impact on a substantial number of small entities. Agencies generally rely on the SBA size standards to identify small entities for RFA purposes. For NMFS, rulemaking activities that have been impacted by changes to the size standards for defining ''small'' businesses include, but are not limited to, regulatory actions and analyses undertaken pursuant to the Magnuson-Stevens Act (MSA), Endangered Species Act (ESA), Marine Mammal Protection Act (MMPA), and National Environmental Policy Act (NEPA). Between 2012 and 2014, NMFS published an average of 285 final rules per year, more than 40 percent of which required an RFA analysis, and a majority of those directly regulated commercial fishing businesses. Thus, NMFS' costs of complying with the RFA are significant even when the small business size standards are stable, and those costs increase substantially when the standards are changing on a recurring basis.

NMFS and the Regional Fishery Management Councils (Councils) have encountered significant difficulties implementing and adjusting to the new standards because: (1) The change was from a single size standard for all commercial fishing businesses to three very different standards, (2) many commercial fishing businesses participate in both finfish and shellfish fishing activities, making it unclear which standard to apply in the RFA analyses, and (3) a number of rules simultaneously implement regulations under fishery management plans for both finfish and shellfish species (for *e.g.,* 76 FR 82044, December 29, 2011; 76 FR 82414, December 30, 2011; 77 FR 15916, March 26, 2012; and 80 FR 41472, July 15, 2015), again making it unclear which standard to apply in the RFA analyses.

Furthermore, one of the RFA's primary purposes is to determine if proposed regulations are expected to have disproportionate economic impacts on small businesses relative to large businesses and, if so, to consider alternatives that would minimize any significant adverse economic impacts on small businesses. Under SBA's current standards for commercial fishing businesses, practically all commercial fishing businesses, and particularly commercial finfish fishing businesses, would likely be determined to be small. Thus, in their RFA analyses, NMFS and the Councils would not be able to discern, consider, or address any disproportionate economic impacts that various regulatory alternatives might have on businesses NMFS and the Councils think are ''small'' in the commercial fishing industry. Such an outcome effectively precludes NMFS from fulfilling one of the RFA's primary purposes and thus is not desirable.

Section 601(3) of the RFA provides that an agency, after consultation with SBA's Office of Advocacy and after an opportunity for public comment, may establish one or more definitions of ''small business'' which are appropriate to the activities of the agency and publish such definition(s) in the **Federal Register**. Further, 13 CFR 121.903(c) states that ''where the agency head is developing a size standard for the sole purpose of performing a Regulatory Flexibility Analysis pursuant to section 601(3) of the Regulatory Flexibility Act, the department or agency may, after consultation with the SBA Office of Advocacy, establish a size standard different from SBA's which is more appropriate for such analysis.'' NMFS and the Department of Commerce General Counsel's Office had preliminary discussions with SBA's Office of Advocacy about these provisions, and SBA was supportive of NMFS using RFA section 601(3) and 13 CFR 121.903(c) to establish its own size standard for the commercial fishing industry for purposes of RFA analyses only.

SBA has also previously expressed support for the idea of creating a single size standard in instances where industries are closely related, as is the case for the commercial finfish and shellfish fishing industries. In its proposed rule to change the size standard for businesses in manufacturing industries (79 FR 54146, Sept. 10, 2014), SBA stated: ''To simplify size standards and for other reasons, SBA may propose a common size standard for closely related industries. Although the size standard analysis may support a separate size standard for each industry, SBA believes that establishing different size standards for closely related industries may not always be appropriate. For example, in cases where many of the same businesses operate in the same multiple industries, a common size standard for those industries might better reflect the Federal marketplace. This might also make size standards among related industries more consistent than separate size standards for each of those industries.'' (79 FR 54146, 54150, Sept. 10, 2014).

NMFS has determined that the data used by SBA's Office of Size Standards to develop the new standards are incomplete and, as a result, not representative of all commercial fishing businesses. Specifically, the data used by SBA only account for commercial fishing businesses that have employees (*i.e.,* employer firms), and thus do not include commercial fishing businesses that do not have employees (*i.e.,* non-employer firms). Non-employer commercial fishing businesses typically pay their self-employed crew a percentage of the gross or net revenue on each commercial fishing trip rather than a standard wage or salary, and thus self-employed crew are not considered employees. Commercial fishing businesses with employees represent only about 3 percent of all commercial fishing businesses, while the other 97 percent are non-employer firms.

Further, according to SBA, annual gross revenues for finfish and shellfish commercial fishing businesses with employees average $1.6 and $0.6 million, respectively. Conversely, NMFS determined the annual gross revenues for commercial fishing businesses without employees is only about $44,000 on average. Thus, NMFS concluded the exclusion of commercial fishing businesses without employees is primarily responsible for the magnitude of the size standard increases, particularly for finfish fishing businesses, and the standards would have been very different if SBA had used data for all commercial fishing businesses. Because the size standards apply to all commercial fishing businesses, not just those with employees, when used to analyze the economic impacts of management actions on directly regulated entities under the RFA, NMFS thinks it is more appropriate to have size standards for RFA purposes that are based on all commercial fishing businesses.

In conjunction with its recent review of size standards, SBA developed a ''Size Standards Methodology'' for establishing, reviewing, and modifying size standards, where necessary. SBA included it as a supporting document in the electronic docket of the September 11, 2012, proposed rule to change the size standards for the three sectors of the commercial fishing industry (77 FR 55755) at *www.regulations.gov.* Application of this new methodology resulted in the significantly different size standards for the three separate sectors of the industry. NMFS referenced this document in developing the proposed size standard in this proposed rule. Consistent with that methodology, SBA used the following industry factors to establish the current size standards for NAICS Sector 11 (Agriculture, Forestry, Fishing, and Hunting): Average firm size, as measured by simple average receipts and weighted average receipts; average assets size; the four-firm concentration ratio (*i.e.,* the percentage of receipts accounted for by the four largest firms in the industry); and the Gini coefficient, which measures the degree of inequality in the distribution of firms by receipts size class under SBA's approach.

SBA's primary source of industry data used in the rule to establish the new size standards for the three sectors of the commercial fishing industry was a special tabulation of the 2007 County Business Patterns data from the U.S. Bureau of Census (Census Bureau). This special tabulation provided SBA with data on the number of employer firms, number of establishments, number of employees, annual payroll, and annual receipts of companies by U.S. industry (6-digit NAICS code). These data were arrayed by various classes of firms' size based on the overall number of employees and gross receipts of the entire enterprise (all establishments and affiliated firms) from all industries. These data allowed SBA to estimate average firm size, the four-firm concentration ratio, and the Gini coefficient.

SBA's Office of Size Standards provided these data upon request to NMFS. NMFS subsequently requested and received from the Census Bureau comparable data for non-employer businesses. NMFS aggregated data to the industry level (*i.e.,* NAICS 11411) for employer and non-employer businesses and then combined these data. Although data confidentiality was not an issue with the non-employer data, prior to aggregation NMFS had to estimate total gross receipts in certain receipts classes for employer firms where the Census Bureau determined the data were confidential and thus could not be released. The combined data provide a complete accounting of the distribution of businesses and receipts by receipt size class category for all commercial fishing businesses. NMFS used these data to generate estimates of certain industry factors needed to establish a single size standard for the commercial fishing businesses, consistent with SBA's methodology to the extent practicable.

Specifically, NMFS used the data it received from SBA and the Census Bureau to generate estimates of simple average receipts, weighted average receipts, and the Gini coefficient. For simple average receipts, each firm's share of the industry's total receipts is weighted equally, whereas the shares of larger firms receive larger weights in estimating weighted average receipts. Weighted average receipts and the Gini coefficient were estimated using the equations provided in SBA's Size Standards Methodology document. NMFS generated the following estimates for the commercial fishing industry: $77,178 for simple average receipts, $12,322,365 for weighted average receipts, and 0.755 for the Gini coefficient. Based on the information in Table 2 of SBA's proposed rule to change the size standards for the finfish, shellfish, and other marine fishing sectors of the commercial fishing industry (77 FR 55755), these estimates support size standards of $5 million, $5 million, and $19 million, respectively.

SBA also considers the average assets size of firms to be an important factor in establishing a size standard. NMFS does not possess and was not able to procure assets size data for non-employer businesses. SBA has such data for employer firms in the finfish and shellfish sectors, though not for employer firms in the other marine fishing sector because of the very small number of firms in that sector. The number of firms in the other marine fishing sector is very small because it includes firms primarily involved in the harvest of corals, sponges, reef associated plants (*e.g.,* algae), and aquarium trade species, whose allowable harvest levels are very small. However, SBA had to purchase the assets size data for employer firms in the finfish and shellfish sectors from a private source and thus could not share the data with NMFS due to their proprietary nature. Therefore, NMFS created an estimate based on data that SBA published in its proposed rule, using the following approach.

According to SBA's proposed rule, the average assets sizes for the finfish and shellfish commercial fishing sectors are $1.4 million and $0.4 million, respectively. Finfish fishing firms and shellfish fishing firms represent approximately 54 percent and 46 percent, respectively, of the 2,039 employer firms in those two sectors combined. Based on these percentages, the weighted average assets size of the combined finfish and shellfish commercial fishing sectors is approximately $0.94 million. Based on Table 2 in SBA's proposed rule, this estimate supports a $7 million size standard.

SBA does not consider the average receipts of the four largest firms to be an important factor in establishing a size standard for industries where the four-firm concentration ratio is below 40 percent (*i.e.,* receipts of the 4 largest firms account for less than 40 percent of the total receipts). According to the data

SBA provided to NMFS, the four largest firms in the commercial fishing industry are commercial finfish fishing businesses. Within the finfish sector, these firms only account for 29 percent of total receipts within that sector. Therefore, within the larger commercial fishing industry as a whole, the percentage of receipts they account for must be less than 29 percent. Because the four largest firms account for less than 40 percent of the total receipts for the commercial fishing industry, consistent with SBA's methodology, NMFS did not use the four-firm concentration ratio in establishing a single size standard for the commercial fishing industry.

According to SBA's methodology, all factors should be weighted equally. Therefore, NMFS averaged the standards supported by the simple average receipts ($5 million), weighted average receipts ($5 million), Gini coefficient ($19 million), and average assets size ($7 million) estimates, which results in a size standard of $9 million. However, SBA only allowed for eight size standards in its final rule (79 FR 54146, September 10, 2014): $5 million, $7 million, $10 million, $14 million, $19 million, $25.5 million, $30 million, and $35.5 million. When the estimated size standard is not equivalent to one of these eight standards, SBA rounds up to the next highest size standard. For NMFS' estimated $9 million size standard, the next highest size standard would be $10 million. If the average assets size factor is not included, because it is based on aggregated employer data only rather than a combination of employer and non-employer data, the average of the other 3 factors is $9.67 million. Thus, the next highest size standard would still be $10 million.

NMFS is aware the Census Bureau has recently released the 2012 County Business Patterns data for employer firms. However, 2012 data for non-employer firms has not yet been released. As previously discussed, NMFS does not think it is prudent to propose a size standard based only on employer data because 97 percent of the commercial fishing businesses are non-employers. Further, even if the 2012 non-employer data is released and NMFS generates new estimates of the various industry factors, NMFS would still not be able to determine what standards are implied by the new estimates until SBA generates an updated version of Table 2 in its proposed rule to change the size standards for the finfish, shellfish, and other marine fishing sectors of the commercial fishing industry (77 FR 55755) using 2012 rather than 2007 data.

As previously stated, SBA recently implemented a rule to adjust all of its receipts based size standards for inflation using the chain-type price index for the U.S. Gross Domestic Product (GDP price index) (79 FR 33647, June 12, 2014). According to that rule, for all industries with a non-inflation-adjusted size standard of $10 million, the new inflation-adjusted size standard is $11 million.

Thus, this rule proposes to establish a small business size standard of $11 million for all businesses in the commercial fishing industry (NAICS 11411) for RFA compliance purposes only. This single size standard for commercial fishing businesses would be used in all RFA analyses conducted in support of NMFS' regulatory actions. Establishing this single size standard would simplify the RFA analyses done in support of NMFS' rules, better meet the RFA's intent by more accurately representing expected disproportionate effects of NMFS' rules between small and large commercial fishing businesses, create a standard that more accurately reflects the size distribution of all businesses in the commercial fishing industry, and allow NMFS to determine when changes to the standard are necessary and appropriate.

Consistent with SBA's review requirements under the Small Business Jobs Act of 2010 and 13 CFR 121.102, NMFS also proposes to review this standard at least once every 5 years to determine if a change is warranted. A change may be warranted because of changes in industry structure, market conditions, inflation, or other relevant factors. The reviews for these potential reasons will be conducted simultaneously in order to minimize the frequency of changes to the standard and additional rulemakings.

Consistent with the requirements in 13 CFR 121.903(c), NMFS will formally consult SBA's Office of Advocacy to ensure their concurrence with this proposed action.

Classification

Pursuant to section 601(3) of the RFA, the NMFS Assistant Administrator has determined that this proposed rule is consistent with the RFA and other applicable law, subject to further consideration after public comment.

This proposed rule has been determined by the Office of Management and Budget to be significant for purposes of Executive Order 12866 because it raises novel legal or policy issues arising out of legal mandates, the President's priorities, or the principles set forth in the Executive Order.

The Chief Counsel for Regulation of the Department of Commerce certified to the Chief Counsel for Advocacy of the SBA that this rule, if adopted, would not have a significant economic impact on a substantial number of small entities. The factual basis for this determination is as follows.

The purposes of the rule are to establish a single small business size standard of $11 million in annual gross receipts for the commercial fishing industry (NAICS 11411), for RFA compliance purposes only, and a requirement for NMFS to assess at least once every 5 years whether this size standard should be changed. The objectives of the rule are to simplify the RFA analyses done in support of NMFS' rules, better meet the RFA's intent by more accurately representing expected disproportionate effects of NMFS' rules between small and large businesses, create a standard that more accurately reflects the size distribution of all businesses in the commercial fishing industry, and allow NMFS to determine when changes to the standard are necessary and appropriate. The RFA and 13 CFR 121.903(c) serve as the legal basis for the rule.

The actions in this rule are administrative in nature and thus would only potentially generate indirect economic effects on commercial fishing businesses. Specifically, the proposed size standard would only affect how NMFS and the Councils determine whether commercial fishing businesses directly regulated by future regulatory actions are small or large, whether and to what extent those actions have disproportionate economic impacts on those two classes of businesses, and when it is appropriate for NMFS to change the standard in the future. This rule would not impose any new requirements on commercial fishing businesses. Therefore, no small entities would be directly regulated by this rule. This rule would not be expected to affect the behavior or operations of commercial fishing businesses. As such, this rule is not expected to generate any direct economic effects on commercial fishing businesses.

Based on the information above, a reduction in profits for a substantial number of small entities is not expected. Because this rule, if implemented, is not expected to have a significant economic impact on a substantial number of small entities, an IRFA is not required and none has been prepared.

No duplicative, overlapping, or conflicting Federal rules have been identified. This rule would not establish any new reporting or record-keeping requirements.

List of Subjects in 50 CFR Part 200

Commercial fishing, Small businesses.

Dated: September 14, 2015.

Samuel D. Rauch III,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

For the reasons set out in the preamble, NMFS proposes to add 50 CFR part 200 under subchapter A to read as follows:

SUBCHAPTER A—GENERAL PROVISIONS

PART 200—SMALL BUSINESS SIZE STANDARDS ESTABLISHED BY NMFS FOR REGULATORY FLEXIBILITY ACT COMPLIANCE PURPOSES ONLY

Sec.
200.1 Purpose and scope.
200.2 Small business size standards and frequency of review.

Authority: 5 U.S.C. 601 *et seq.*

§ 200.1 Purpose and scope.

(a) This part sets forth the National Marine Fisheries Service (NMFS) small business size standards for NMFS to use in conducting Regulatory Flexibility Act (RFA) analyses for NMFS actions subject to the RFA. This part also sets forth the timeframe for NMFS to review its small business size standards.

(b) NMFS has established the alternative size standards in this part, for RFA compliance purposes only, in order to simplify the RFA analyses done in support of NMFS' rules, better meet the RFA's intent by more accurately representing expected disproportionate effects of NMFS' rules between small and large businesses, create a standard that more accurately reflects the size distribution of all businesses in the industry, and allow NMFS to determine when changes to the standard are necessary and appropriate.

§ 200.2 Small business size standards and frequency of review.

(a) NMFS' small business size standard for businesses, including their affiliates, whose primary industry is commercial fishing is $11 million in annual gross receipts. This standard applies to all businesses classified under North American Industry Classification System (NAICS) code 11411 for commercial fishing, including all businesses classified as commercial finfish fishing (NAICS 114111), commercial shellfish fishing (NAICS 114112), and other commercial marine fishing (NAICS 114119) businesses.

(b) NMFS will review each of the small business size standards in paragraph (a) of this section at least once every 5 years to determine if a change is warranted. A change may be warranted because of changes in industry structure, market conditions, inflation, or other relevant factors.

[FR Doc. 2015–23375 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

Notices

Federal Register

Vol. 80, No. 181

Friday, September 18, 2015

DEPARTMENT OF AGRICULTURE

Agricultural Marketing Service

Submission for OMB Review; Comment Request

The Department of Agriculture will submit the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13 on or after the date of publication of this notice. 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; (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: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), New Executive Office Building, Washington, DC; New Executive Office Building, 725 17th Street NW., Washington, DC 20503. Commenters are encouraged to submit their comments to OMB via email to: *OIRA_Submission@omb.eop.gov* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602.

Comments regarding these information collections are best assured of having their full effect if received by October 19, 2015. Copies of the submission(s) may be obtained by calling (202) 720–8681.

An agency 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.

Agricultural Marketing Service

Title: Reporting Requirements under Regulations Governing Inspection and Grading Services of Manufactured or Processed Dairy Products and the Certification of Sanitary Design & Fabrication of Equipment used in the Slaughter, Processing, and Packaging of Livestock and Poultry Products.

OMB Control Number: 0581–0126.

Summary of Collection: The Agricultural Marketing Act (AMA) of 1946 (7 U.S.C. 1621–1627), directs and authorizes the Department to develop standards of quality, condition, quantity, grading programs, and services to enable a more orderly marketing of agricultural products. The regulations governing the voluntary inspection and grading program for dairy products is contained in 7 CFR part 58. The certification regulations for livestock and poultry products are contained in 7 CFR part 54. The Government, industry and consumer will be well served if the Government can help insure that dairy products are produced under sanitary conditions and that buyers have the choice of purchasing the quality of the product they desire. The dairy grading program is a voluntary user fee program. In order for a voluntary inspection program to perform satisfactorily with a minimum of confusion, information must be collected to determine what services are requested.

Need and Use of the Information: The information collected is used to identify the product offered for grading; to identify and contact the individuals responsible for payment of the grading or equipment evaluation fee and expense; and to identify the person responsible for administering the grade label program. The Agriculture Marketing service will use several forms to collect essential information to carry out and administer the inspection and grading program.

Description of Respondents: Business or other for profit.

Number of Respondents: 168.

Frequency of Responses: Reporting: On occasion.

Total Burden Hours: 2,252.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2015–23404 Filed 9–17–15; 8:45 am]

BILLING CODE 3410–02–P

DEPARTMENT OF AGRICULTURE

Farm Service Agency

Information Collection Request; Servicing Minor Program Loans

AGENCY: Farm Service Agency, USDA.

ACTION: Notice and request for comments.

SUMMARY: In accordance with the Paperwork Reduction Act of 1995, the Farm Service Agency (FSA) is requesting comments from all interested individuals and organizations on an extension of a currently approved information collection to support the Servicing Minor Program Loans.

DATES: We will consider comments that we receive by November 17, 2015.

ADDRESSES: We invite you to submit comments on this notice. In your comments, include the date, volume, and page number of this issue of the **Federal Register**, the OMB control number and the title of the information collection. You may submit comments by any of the following methods:

- Federal eRulemaking Portal: Go to *http://www.regulations.gov*. Follow the online instructions for submitting comments.
- Mail: Cindy Van Nostrand, Loan Servicing and Properties Management Division, USDA, FSA, Farm Loan Programs, 1400 Independence Ave. SW., Mail Stop 0523, Washington, DC 20250–00523.

You may also send comments to the Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503.

FOR FURTHER INFORMATION CONTACT: Cindy Van Nostrand, (202) 720–0900.

SUPPLEMENTARY INFORMATION:

Title: Servicing Minor Program Loans.

OMB Control Number: 0560–0230.

Expiration Date: March 31, 2016.

Type of Request: Extension.

Abstract: Section 331(b) of the Consolidated Farm and Rural Development Act (CONTACT, 7 U.S.C. 1981(b)), in part, authorizes the Secretary of Agriculture to modify, subordinate and release terms of security instruments, leases, contracts, and agreements entered into by FSA. That section also authorizes transfers of security property, as the Secretary deems necessary, to carry out the purpose of the loan or protect the Government's financial interest. Section 335 of the CONACT (7 U.S.C. 1985) provides servicing authority for real estate security; operation or lease of realty; disposition of property; conveyance of real property interest of the United States; easements; and condemnations.

The information collection relates to a program benefit recipient or loan borrower requesting action on security they own, which was purchased with FSA loan funds, improved with FSA loan funds or has otherwise been mortgaged to FSA to secure a Government loan. The information collected is primarily financial data not already on file, such as borrower asset values, current financial information and public use and employment data.

The formulas used to calculate the total burden hours is ''the estimated average time per respondents'' times ''the total estimated annual response.''

Estimate of Annual Burden: Public reporting burden for this collection of information is estimated to average .64 hours per response.

Respondents: Individuals, associations, partnerships, or corporations.

Estimated Number of Respondents: 58.

Estimated Number of Responses per Respondent: 1.

Estimated Total Annual of Responses: 58.

Estimated Average Time per Response: 0.64 hours.

Estimated Total Annual Burden on Respondents: 37 hours.

We are requesting comments on all aspects of this information collection to help us:

(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 collection of information including the validity of the methodology and assumptions used;

(3) Evaluate the quality, utility, and clarity of the information technology; and

(4) Minimize the burden of the information collection on those who respond through the use of appropriate automated, electronic, mechanical, or other technological collection techniques or other forms of information technology.

All comments received in response to this notice, including names and addresses where provided, will be made a matter of public record. Comments will be summarized and included in the request for OMB approval of the information collection.

Val Dolcini,

Administrator, Farm Service Agency.

[FR Doc. 2015–23430 Filed 9–17–15; 8:45 am]

BILLING CODE 3410–05–P

DEPARTMENT OF AGRICULTURE

Food Safety and Inspection Service

Submission for OMB Review; Comment Request

September 14, 2015.

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the Paperwork Reduction Act of 1995, Public Law 104–13. 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; (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: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), *OIRA_Submission@OMB.EOP.GOV* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. 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 (202) 720–8958.

An agency 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.

Food Safety and Inspection Service

Title: Certificate of Medical Examination.

OMB Control Number: 0583—New.

Summary of Collection: The Food Safety and Inspection Service (FSIS) has been delegated the authority to exercise the functions of the Secretary as provided in the Federal Meat Inspection Act (FMIA) (21 U.S.C. 601 *et seq.*), the Poultry Products Inspection Act (PPIA) (21 U.S.C. 451 *et seq.*), and the Egg products Inspection Act (EPIA) (21 U.S.C. 1031 *et. seq.*). These statutes mandate that FSIS protect the public by ensuring that meat and poultry products are safe, wholesome, unadulterated, and properly labeled and packaged. FSIS will use a new form FSIS 4339–1, Certificate of Medical Examination (with Report of Medical History) to collect information from applicant.

Need and Use of the Information: FSIS will use the information from FSIS 4339–1 form to determine whether or not an applicant for an FSIS Food Inspector, Consumer Safety Inspector, or Veterinary Medical Officer in-plant position meets the Office of Personnel management approved medical qualification standards. This new form will ensure accurate collection of the required data.

Description of Respondents: Individuals or households.

Number of Respondents: 500.

Frequency of Responses: Recordkeeping; Reporting: On occasion.

Total Burden Hours: 750.

Ruth Brown,

Departmental Information Collection Clearance Officer.

[FR Doc. 2015–23405 Filed 9–17–15; 8:45 am]

BILLING CODE 3410–DM–P

DEPARTMENT OF AGRICULTURE

Forest Service

Submission for OMB Review; Comment Request

The Department of Agriculture has submitted the following information collection requirement(s) to OMB for review and clearance under the

Paperwork Reduction Act of 1995, Public Law 104–13. 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; (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 and other forms of information technology.

Comments regarding this information collection received by October 19, 2015 will be considered. Written comments should be addressed to: Desk Officer for Agriculture, Office of Information and Regulatory Affairs, Office of Management and Budget (OMB), New Executive Office Building, 725 17th Street NW., Washington, DC, 20503. Commentors are encouraged to submit their comments to OMB via email to: *OIRA_Submission@omb.eop.gov* or fax (202) 395–5806 and to Departmental Clearance Office, USDA, OCIO, Mail Stop 7602, Washington, DC 20250–7602. Copies of the submission(s) may be obtained by calling (202) 720–8681.

An agency 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.

Forest Service

Title: Equal Opportunity Compliance Review Reporting Tool.

OMB Control Number: 0596–0215.

Summary of Collection: All Federal agencies and the entities receiving Federal financial assistance are prohibited from discriminating in the delivery of programs and services. Agencies must comply with equal opportunity laws, Title VI of the Civil Rights Act of 1964, as amended; Title IX of the Education Amendments Act of 1972; The Age Discrimination Act of 1975, as amended; Section 504 of the Rehabilitation Act of 1973, as amended; and Executive orders prohibiting discrimination in the delivery of all programs and services to the public. The Federal government is required to conduct periodic program compliance reviews of recipients of Federal financial assistance to ensure they are adhering to the nondiscrimination statutes. Forest Service personnel integral to the pre-award and post-award process will collect this information during face-to-face meetings or telephone interviews.

Need and Use of the Information: Forest Service will use form series FS–1700–6, ''Equal Opportunity Compliance Review Record'' to collect the information and document assisted program compliance. Data collected includes information on actions taken by recipients to ensure the public receives service without discrimination or barriers to access and the recipients' employees understand their customer service responsibilities. The information collected is for internal use only and is utilized to establish and monitor civil rights compliance.

Description of Respondents: Business or other for-profit; Not-for-profit Institutions; State, Local or Tribal Government.

Number of Respondents: 11,800.

Frequency of Responses: Recordkeeping; Reporting: On occasion.

Total Burden Hours: 11,904.

Charlene Parker,

Departmental Information Collection Clearance Officer.

[FR Doc. 2015–23406 Filed 9–17–15; 8:45 am]

BILLING CODE 3411–15–P

DEPARTMENT OF COMMERCE

Bureau of Industry and Security

Renewal of Order Temporarily Denying Export Privileges: Flider Electronics, LLC a/k/a Flider Electronics d/b/a Trident International Corporation d/b/a Trident International d/b/a Trident International Corporation, LLC, 837 Turk Street, San Francisco, California 94102; Pavel Semenovich Flider a/k/a Pavel Flider, 21 Eye Street, San Rafael, California 94901; and Gennadiy Semenovich Flider a/k/a Gennadiy Flider, 699 36th Avenue #203, San Francisco, California 94121

Pursuant to Section 766.24 of the Export Administration Regulations (the ''Regulations'' or ''EAR''),[1] I hereby grant the request of the Office of Export Enforcement (''OEE'') to renew the March 23, 2015 Amended Order Temporarily Denying the Export Privileges of Flider Electronics, LLC, a/k/a Flider Electronics, d/b/a Trident International Corporation, d/b/a Trident International, d/b/a Trident International Corporation, LLC (''Trident'' or ''Flider Electronics, LLC, d/b/a Trident International Corporation''); Pavel Semenovich Flider a/k/a Pavel Flider (''Pavel Flider''); and Gennadiy Semenovich Flider a/k/a Gennadiy Flider (''Gennadiy Flider''). I find that renewal of the Temporary Denial Order (''TDO'') is necessary in the public interest to prevent imminent violation of the EAR.

I. Procedural History and Background

On March 19, 2015, I signed the TDO, which denied for 180 days the export privileges of Trident, as well as Pavel Flider, the president and owner of Trident, and Gennadiy Flider, also a Trident office manager, with responsibilities relating directly to the procurement and export activities referenced in the TDO. As discussed in detail in the TDO, OEE presented evidence of a pattern of exports by Trident from the United States to Russia, via transshipment through Estonia or Finland, involving false statements and other evasive actions or schemes designed to camouflage the actual destination, end uses, and/or end users of the U.S.-origin items that Trident was exporting on an ongoing basis. These U.S.-origin items included items listed on the Commerce Control List (''CCL'') and subject to national security-based license requirements. Accordingly, pursuant to Section 766.24 of the Regulations, I found that the TDO was necessary to prevent further and imminent violation of the EAR by Trident, and pursuant to Section 766.23, found that it was necessary, in order to prevent evasion of the TDO, to add Pavel Flider and Gennadiy Flider to the TDO as related persons to Trident.

The TDO was issued *ex parte* pursuant to Section 766.24(a), and went into effect upon issuance on March 19, 2015. I subsequently amended the TDO on March 23, 2015 making limited revision to page 6 of the March 19, 2015 order, without changing my findings or the terms of the order issued on March 19, 2015. The March 23, 2015 amended order did not change the denial period, which continued to run for 180 days

[1] The Regulations are currently codified at 15 CFR parts 730–774 (2015). The EAR issued under the Export Administration Act of 1979, as amended (50 U.S.C. app. §§ 2401–2420 (2000)) (''EAA''). Since August 21, 2001, the Act has been in lapse and the President, through Executive Order 13222 of August 17, 2001 (3 CFR, 2001 Comp. 783 (2002)), which has been extended by successive Presidential Notices, the most recent being that of August 7, 2015 (80 FR 48233 (Aug. 11, 2015)), has continued the Regulations in effect under the International Emergency Economic Powers Act (50 U.S.C. 1701, *et seq.*) (2006 & Supp. IV 2010).

from March 19, 2015, that is, through and including September 14, 2015, subject to potential renewal upon timely application by OEE, as clearly set forth in the TDO. Copies of both the original and amended TDO were sent to each party named in the relevant order in accordance with Section 766.5 and 766.24(d) of the Regulations, and the original and amended TDOs were published in the **Federal Register** on March 26, 2015, and March 30, 2015, respectively. *See* 80 FR 15979 (March 26, 2015); 80 FR 16632 (March 30, 2015).

On August 21, 2015, OEE submitted a written request for renewal of the TDO. This request was timely made under Section 766.24(d) (BIS may request renewal of a temporary denial order no later than 20 days before the expiration date of the order).

Notice of the renewal request was provided to Trident, the respondent, in accordance with Sections 766.5 and 766.24(d) of the Regulations, via both service upon Trident and its president and owner, Pavel Flider. No opposition has been received from Trident.[2]

II. TDO Renewal

A. Legal Standard

Pursuant to Section 766.24, BIS may issue or renew an order temporarily denying a respondent's export privileges upon a showing that the order is necessary in the public interest to prevent an ''imminent violation'' of the Regulations. 15 CFR 766.24(b)(1) and 776.24(d). ''A violation may be 'imminent' either in time or degree of likelihood.'' 15 CFR 766.24(b)(3). BIS may show ''either that a violation is about to occur, or that the general circumstances of the matter under investigation or case under criminal or administrative charges demonstrate a likelihood of future violations.'' *Id.* As to the likelihood of future violations, BIS may show that the violation under investigation or charge ''is significant, deliberate, covert and/or likely to occur again, rather than technical or negligent [.]'' *Id.* A ''lack of information establishing the precise time a violation may occur does not preclude a finding that a violation is imminent, so long as there is sufficient reason to believe the likelihood of a violation.'' *Id.*

B. Request for Renewal

OEE's request for renewal is based upon the facts underlying the issuance of the TDO and the evidence developed over the course of this investigation, including evidence discussed in the TDO and summarized in Section I., *supra.* OEE's ongoing investigation of Trident, in conjunction with the United States Attorney's Office for the Northern District of California, included the execution of a search warrant at Trident's place of business and Pavel Flider's residence on or about March 18, 2015, and at two storage lockers on or about April 10, 2015.

Despite the issuance of the TDO and the execution of the search warrants, Trident repeatedly sought to order or buy items subject to the EAR from a U.S.-based electronics distributor from whom Trident had previously purchased items for export. Beginning on or about July 10, 2015, through on or about July 21, 2015, while the TDO by its plain terms remained in effect, Pavel Flider contacted employees of this electronics distributor requesting to reestablish Trident's account and make additional purchases of electronic components, including for computer chips. Several of the distributor's employees were solicited in an effort to place additional purchase orders for more computer chips for Trident. The computer chips, which OEE has reason to believe were intended for export based upon the respondents' conduct both prior to and after issuance of the TDO,[3] are subject to the EAR.

The distributor declined to accept or fill the orders following each attempt or solicitation by Trident. Finally, on or about July 21, 2015, a senior official of the distributor contacted Pavel Flider by phone to inform him that it was the distributor's corporate policy not to conduct additional business with a company such as Trident. Nonetheless, both during and shortly after this call, Pavel Flider again attempted to solicit purchases for more electronic components, stating that Trident would resume exporting in September 2015, following expiration of the TDO.

The TDO at all times over the last 180 days broadly prohibited the denied parties from participating in any way in any transaction involving any item subject to the EAR that is to be exported from the United States, including, but not limited to, carrying on negotiations concerning, ordering, or buying any such item. Similarly, it prohibited any of the denied parties from benefitting in any way from any transaction involving any such item. Likewise, both prior to issuance of the TDO and during the denial period, the EAR prohibited, inter alia, acting contrary to the terms of a temporary denial order or other type or form of denial order (see Section 764.2(k)), attempting to violate or soliciting a violation of the EAR or any order issued thereunder (see Section 764.2(c)), or engaging in any transaction or taking any other action with intent to evade the EAR or any order issued thereunder (see Section 764.2(h)). In addition, as referenced above, the TDO plainly stated that it was subject to renewal.

C. Findings

I find that the overall record here, as discussed above and in the TDO as issued and amended in March 2015, demonstrates that renewal of the TDO is necessary to avoid imminent violation of the EAR, based upon the evidence presented by OEE of deliberate and evasive conduct both pre- and post-issuance of the TDO. Accordingly, renewal of the TDO is needed to provide continued notice to persons in the United States and abroad that they should not deal with respondent Trident, or with related and denied persons Pavel Flider and Gennadiy Flider, in connection with any exports, reexports, or other transactions involving any items subject to the EAR or any other activities subject to the EAR. Doing so is consistent with the public interest to preclude future violations of the EAR.

It is therefore ORDERED:

First, that Flider Electronics, LLC, a/k/a Flider Electronics, d/b/a Trident International Corporation, d/b/a Trident International d/b/a Trident International Corporation, LLC, 837 Turk Street, San Francisco, California 94102; Pavel Semenovich Flider, a/k/a Pavel Flider, 21 Eye Street, San Rafael, California 94901; and Gennadiy Semenovich Flider, a/k/a Gennadiy Flider, 699 36th Avenue #203, San Francisco, California 94121, and when acting for or on their behalf, any successors or assigns, agents, or employees (each a ''Denied Person'' and collectively the ''Denied Persons'') may not, directly or indirectly, participate in any way in any transaction involving any commodity, software or technology (hereinafter

[2] Parties named as related persons may appeal whether their addition as related persons accords with Section 766.23 of the Regulations, but may not challenge the issuance or oppose the renewal of the underlying TDO. *See* Section 766.24(d)(3)(ii). Neither Pavel Flider nor Gennadiy Flider has ever appealed or otherwise responded to their inclusion as related persons.

[3] In addition, during an interview on March 18, 2015, with BIS Special Agents, along with agents from the Department of Homeland Security, Pavel Flider stated that Trident had a single customer in Estonia named Adimir OU (''Adimir'') between 2000–2013, and that all items sent to Adimir were transshipped to Russia, including large volumes of items classified as Export Control Classification Number (''ECCN'') 3A001.a.2.c. Beginning in 2014, however, Trident began exporting directly to Russia. Pavel Flider confirmed that Trident did not apply for or obtain an export license from BIS for any of the items exported from the United States.

collectively referred to as ''item'') exported or to be exported from the United States that is subject to the Export Administration Regulations (''EAR''), or in any other activity subject to the EAR including, but not limited to:

A. Applying for, obtaining, or using any license, License Exception, or export control document;

B. Carrying on negotiations concerning, or ordering, buying, receiving, using, selling, delivering, storing, disposing of, forwarding, transporting, financing, or otherwise servicing in any way, any transaction involving any item exported or to be exported from the United States that is subject to the EAR, or in any other activity subject to the EAR; or

C. Benefitting in any way from any transaction involving any item exported or to be exported from the United States that is subject to the EAR, or in any other activity subject to the EAR.

Second, that no person may, directly or indirectly, do any of the following:

A. Export or reexport to or on behalf of a Denied Person any item subject to the EAR;

B. Take any action that facilitates the acquisition or attempted acquisition by a Denied Person of the ownership, possession, or control of any item subject to the EAR that has been or will be exported from the United States, including financing or other support activities related to a transaction whereby a Denied Person acquires or attempts to acquire such ownership, possession or control;

C. Take any action to acquire from or to facilitate the acquisition or attempted acquisition from a Denied Person of any item subject to the EAR that has been exported from the United States;

D. Obtain from a Denied Person in the United States any item subject to the EAR with knowledge or reason to know that the item will be, or is intended to be, exported from the United States; or

E. Engage in any transaction to service any item subject to the EAR that has been or will be exported from the United States and which is owned, possessed or controlled by a Denied Person, or service any item, of whatever origin, that is owned, possessed or controlled by a Denied Person if such service involves the use of any item subject to the EAR that has been or will be exported from the United States. For purposes of this paragraph, servicing means installation, maintenance, repair, modification or testing.

THIRD, that, after notice and opportunity for comment as provided in Section 766.23 of the EAR, any other person, firm, corporation, or business organization related to a Denied Person by ownership, control, position of responsibility, affiliation, or other connection in the conduct of trade or business may also be made subject to the provisions of this Order.

In accordance with the provisions of Section 766.24(e) of the EAR, Flider Electronics, LLC, d/b/a Trident International Corporation, may, at any time, appeal this Order by filing a full written statement in support of the appeal with the Office of the Administrative Law Judge, U.S. Coast Guard ALJ Docketing Center, 40 South Gay Street, Baltimore, Maryland 21202–4022. In accordance with the provisions of Sections 766.23(c)(2) and 766.24(e)(3) of the EAR, Pavel Semenovich Flider and Gennadiy Semenovich Flider may, at any time, appeal his inclusion as a related person by filing a full written statement in support of the appeal with the Office of the Administrative Law Judge, U.S. Coast Guard ALJ Docketing Center, 40 South Gay Street, Baltimore, Maryland 21202–4022.

In accordance with the provisions of Section 766.24(d) of the EAR, BIS may seek renewal of this Order by filing a written request not later than 20 days before the expiration date. Flider Electronics, LLC d/b/a Trident International Corporation may oppose a request to renew this Order by filing a written submission with the Assistant Secretary for Export Enforcement, which must be received not later than seven days before the expiration date of the Order.

A copy of this Order shall be sent to Flider Electronics LLC d/b/a Trident International Corporation and each related person, and shall be published in the **Federal Register**.

This Order is effective upon issuance and shall remain in effect for 180 days.

Dated: September 14, 2015.

David W. Mills,

Assistant Secretary of Commerce for Export Enforcement.

[FR Doc. 2015–23447 Filed 9–17–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF COMMERCE

International Trade Administration

[A–570–900]

Diamond Sawblades and Parts Thereof From the People's Republic of China: Continuation of the Antidumping Duty Order

AGENCY: Enforcement and Compliance, International Trade Administration, Department of Commerce.

SUMMARY: The Department of Commerce (the Department) and the International Trade Commission (the ITC) have determined that revocation of the antidumping duty (AD) order on diamond sawblades and parts thereof (diamond sawblades) from the People's Republic of China (the PRC) would likely lead to continuation or recurrence of dumping and material injury to an industry in the United States. Therefore, the Department is publishing a notice of continuation for this AD order.

DATES: *Effective Date:* September 18, 2015.

FOR FURTHER INFORMATION CONTACT: Yang Jin Chun, AD/CVD Operations, Office I, Enforcement and Compliance, International Trade Administration, U.S. Department of Commerce, 14th Street and Constitution Avenue NW., Washington, DC 20230; telephone: (202) 482–5760.

SUPPLEMENTARY INFORMATION:

Background

In November 2014, the Department initiated [1] and the ITC instituted [2] a five-year sunset review of the AD order on diamond sawblades from the PRC pursuant to sections 751(c) of the Tariff Act of 1930, as amended (the Act). As a result of its review, the Department determined that revocation of the AD order would likely lead to continuation or recurrence of dumping and notified the ITC of the magnitude of the margins likely to prevail should the AD order be revoked, pursuant to sections 751(c)(1) and 752(c) of the Act.[3]

On September 9, 2015, the ITC published its determination that revocation of the AD order on diamond sawblades from the PRC would likely lead to continuation or recurrence of material injury to an industry in the United States within a reasonably foreseeable time, pursuant to sections 751(c) of the Act.[4]

Scope of the Order

The products covered by the order are all finished circular sawblades, whether slotted or not, with a working part that is comprised of a diamond segment or segments, and parts thereof, regardless of specification or size, except as specifically excluded below. Within the scope of the order are semifinished

[1] *See Initiation of Five-Year (''Sunset'') Review,* 79 FR 65186 (November 3, 2014).

[2] *See Diamond Sawblades and Parts Thereof From China; Termination of Previously Instituted Five-Year Review and Institution of Five-Year Review,* 79 FR 65420 (November 4, 2014).

[3] *See Diamond Sawblades and Parts Thereof From the People's Republic of China: Final Results of the Expedited Sunset Review of the Antidumping Duty Order,* 80 FR 12797 (March 11, 2015).

[4] *See Diamond Sawblades and Parts Thereof from China,* 80 FR 54326 (September 9, 2015).

diamond sawblades, including diamond sawblade cores and diamond sawblade segments. Diamond sawblade cores are circular steel plates, whether or not attached to non-steel plates, with slots. Diamond sawblade cores are manufactured principally, but not exclusively, from alloy steel. A diamond sawblade segment consists of a mixture of diamonds (whether natural or synthetic, and regardless of the quantity of diamonds) and metal powders (including, but not limited to, iron, cobalt, nickel, tungsten carbide) that are formed together into a solid shape (from generally, but not limited to, a heating and pressing process).

Sawblades with diamonds directly attached to the core with a resin or electroplated bond, which thereby do not contain a diamond segment, are not included within the scope of the order. Diamond sawblades and/or sawblade cores with a thickness of less than 0.025 inches, or with a thickness greater than 1.1 inches, are excluded from the scope of the order. Circular steel plates that have a cutting edge of non-diamond material, such as external teeth that protrude from the outer diameter of the plate, whether or not finished, are excluded from the scope of the order. Diamond sawblade cores with a Rockwell C hardness of less than 25 are excluded from the scope of the order. Diamond sawblades and/or diamond segment(s) with diamonds that predominantly have a mesh size number greater than 240 (such as 250 or 260) are excluded from the scope of the order.

Merchandise subject to the order is typically imported under heading 8202.39.00.00 of the Harmonized Tariff Schedule of the United States (HTSUS). When packaged together as a set for retail sale with an item that is separately classified under headings 8202 to 8205 of the HTSUS, diamond sawblades or parts thereof may be imported under heading 8206.00.00.00 of the HTSUS. On October 11, 2011, the Department included the 6804.21.00.00 HTSUS classification number to the customs case reference file, pursuant to a request by U.S. Customs and Border Protection (CBP).[5]

The tariff classification is provided for convenience and customs purposes; however, the written description of the scope of the order is dispositive.

Continuation of the Order

As a result of the determinations by the Department and the ITC that revocation of the AD order would likely lead to a continuation or recurrence of dumping and material injury to an industry in the United States, pursuant to section 75l(d)(2) of the Act and 19 CFR 351.218(a), the Department hereby orders the continuation of the AD order on diamond sawblades from the PRC. We will instruct CBP to continue to collect AD cash deposits at the rates in effect at the time of entry for all imports of subject merchandise.

The effective date of the continuation of the AD 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 and 19 CFR 351.218(c)(2), the Department intends to initiate the next five-year review of this order not later than 30 days prior to the fifth anniversary of the effective date of this continuation notice.

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

Dated: September 14, 2015.

Ronald K. Lorentzen,

Acting Assistant Secretary for Enforcement and Compliance.

[FR Doc. 2015–23468 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–DS–P

[5] *See Diamond Sawblades and Parts Thereof From the Republic of Korea: Preliminary Results of Antidumping Duty Administrative Review,* 76 FR 76128 (December 6, 2011).

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE173

Notice of Availability of Community-Based Restoration Program Guidelines

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

ACTION: Notice of availability of Community-based Restoration Program Guidelines; request for comments.

SUMMARY: NOAA's National Marine Fisheries Service (NMFS) is seeking comment on revised guidelines for the Community-based Restoration Program (Program). Since guidelines were first issued in 2000, the Program has not only evolved alongside the field of habitat restoration but has been designed to more effectively support sustainable fisheries and contribute to the recovery and conservation of protected resources. These goals are aligned with NMFS' core mandates, the Magnuson-Stevens Fishery Conservation and Management Act and Endangered Species Act. The Program has built a strong foundation of technical and financial assistance capabilities that enables NOAA to proactively identify and develop priority habitat restoration projects, build community-based partnerships to leverage resources, and implement technically sound restoration actions that have maximum impact on coastal and marine species and the ecosystems on which they depend. This document replaces previous guidelines and describes the Program's goals and scope of implementation for FY 2016 and beyond. This is not a solicitation of project proposals.

DATES: Comments are due October 19, 2015.

ADDRESSES: Additional information about the Program is available at: *http://www.habitat.noaa.gov/restoration/programs/crp.html.* Interested parties that wish to send comments may send an email to *tisa.shostik@noaa.gov.* Interested parties that wish to send comments through regular mail may use the following mailing address: NOAA Restoration Center (F/HC3), ATTN: CRP Guidelines, 1315 East West Highway, RM 14853, Silver Spring, MD 20910.

FOR FURTHER INFORMATION CONTACT: Tisa Shostik at *tisa.shostik@noaa.gov.*

SUPPLEMENTARY INFORMATION:

Background

NMFS started the Community-based Restoration Program (Program) in 1996 to provide technical and financial assistance to support the implementation of community-driven habitat restoration. The Program collaborates with partners to restore coastal wetlands, coral reef, shellfish, estuarine, and riverine habitat to benefit coastal and marine species under NMFS jurisdiction. Restoration implemented under the Program include projects such as dam removal and fish passage projects, hydrologic reconnection projects, shellfish and coral reef restoration projects. To date, the Program has implemented more than 1,700 habitat restoration projects in 37 states. It has restored more than 55,000 acres of habitat and opened 2,500 miles of rivers and streams.

The Program is housed within the NMFS Office of Habitat Conservation's Restoration Center and was authorized in the Magnuson-Stevens Fishery Conservation and Management Reauthorization Act of 2006. Prior guidelines for the Program were provided at 65 FR 16890, March 30, 2000, and then revised at 73 FR 55816, September 26, 2008. Since the guidelines were last updated in 2008, base funding for the Program has remained relatively level, with the exception of several specific initiatives such as the Coastal and Marine Habitat Restoration Grants funded by the American Recovery and Reinvestment Act of 2009 and the Open Rivers Initiative (2007–2010).

Program Guidelines

a. Purpose of These Guidelines

These guidelines provide information to the public and partnering organizations regarding the Program's scope and focus. The guidelines describe the broad range of the Program's activities and influence including, but not limited to, technical and financial assistance capabilities that are managed in a manner to most effectively advance the goals established under NMFS' core mandates. Previous published guidelines included more information on financial assistance mechanisms and procedures. These discussions have been removed from these updated guidelines in order to focus on the Program's goals, scope, and capabilities, rather than administrative process.

b. Program Overview

NMFS' primary goals under its core mandates include ensuring the productivity and sustainability of fisheries and recovering and conserving protected resources. Healthy ecosystems and the availability of habitat are critical to these resources and therefore restoring coastal, marine, and riverine habitat is an essential element of NMFS' strategy to achieve its primary goals. To support this strategy, the Program provides technical and financial assistance to identify, develop, implement, and evaluate community-driven habitat restoration projects that yield the greatest benefit to the resources under NMFS' jurisdiction. Program staff leads coordination efforts across NOAA and other Federal and non-Federal partners to identify shared habitat priorities and focus resource investments to increase the impact of habitat conservation and restoration actions. The Program's restoration specialists, including fish biologists, ecologists, and engineers, located throughout the country, provide comprehensive expertise to facilitate effective habitat restoration. To support project implementation through financial assistance, the Program primarily establishes cooperative agreement funding awards with non-Federal partners. Competitive solicitations are issued as Federal funding announcements on Grants.gov. Non-Federal partners may include non-governmental organizations, tribes, states, and local government agencies and communities.

Habitat restoration projects implemented through the Program are developed in partnership with the communities in which they are based and reflect the needs and interests of local stakeholders. As restoration is conducted using a collaborative, ecosystem approach, projects such as dam removal, floodplain reconnection, and coastal wetland restoration often result in multiple benefits beyond the Program's primary goals. These benefits may include increased coastal resiliency, improved infrastructure, enhanced public safety, increased recreational opportunities, and strengthened coastal economies. The Program also fosters natural resource stewardship and local community engagement by supporting outreach, education, or volunteer opportunities as restoration project components.

c. Program Activities and Priorities

The Program will continue to support projects featuring all aspects of coastal habitat restoration, conservation, and protection that recover threatened and endangered species listed under the Endangered Species Act, sustain or help rebuild fish stocks managed under the Magnuson-Stevens Fishery Conservation and Management Act, or benefit other coastal and marine species with a connection to NMFS management. Within this broad authority, the Program is focusing its efforts to more effectively achieve NMFS' species recovery and fisheries sustainability goals, as well as demonstrate the results and multiple benefits of the Program's investments. Focused and coordinated approaches are critical because funding for coastal habitat restoration remains insufficient to fully address the needs of all habitat-limited coastal and marine species. To help set priorities and inform strategic decisions on where and how the Program targets its efforts, Program staff coordinates across NOAA and develops key partnerships with other Federal agencies, tribes, states, counties, local communities, and other non-governmental organizations. This leadership and collaboration helps set shared priorities and goals, and increases the impact of the Program's coastal restoration funding by leveraging resources and coordinating investments from multiple habitat restoration and conservation organizations and programs involved in habitat conservation and restoration.

To execute the Program's targeted habitat restoration goals, the Program may focus its technical assistance and funding on specific geographic areas, habitats, restoration techniques, actions identified in protected species recovery plans or fishery management plans, or where NOAA and partner resources are aligned to yield a greater collective impact. The Program will provide restoration project funding to non-Federal partners through open, competitive solicitations announced through Federal Funding Opportunities (FFOs). The Program's targeted goals and priorities will be explicitly outlined within each FFO and applications will be evaluated on how well the proposed activity meets those priorities. Funding may be provided through cooperative agreements for restoration planning and feasibility studies, engineering and design, implementation and construction, and monitoring and evaluation efforts.

In addition to providing funds for restoration projects, the Program provides leadership and technical expertise to foster the development and implementation of habitat restoration actions that support the recovery of protected species and sustainability of fisheries. To most effectively meet these core mandate goals, Program staff proactively identifies restoration opportunities, coordinates with other entities to help drive investments towards the highest priorities, and develops solutions to overcome obstacles to restoration success. Program staff provides technical expertise to ensure that restoration partners have the necessary support to successfully carry out complex habitat restoration activities such as dam removals and large-scale hydrologic reconnection projects. The technical assistance that Program staff provides to restoration project partners includes guidance on project feasibility assessments, engineering and design, project implementation oversight, regulatory compliance, and monitoring planning. The Program also accelerates the delivery of resources and implementation of restoration by streamlining permitting and environmental compliance processes when possible through the development and use of programmatic approaches. These core technical and financial assistance capabilities enable the Program to efficiently support the implementation of other targeted habitat conservation and restoration initiatives within NOAA.

As the practice of habitat restoration has developed, the Program has contributed to its advancement through targeted implementation and effectiveness monitoring and technology transfer. Monitoring carried out by the Program has supported science-based decision making and led to improvements in the design and implementation of habitat restoration projects. To evaluate the effectiveness of restoration actions in a cost-effective way, the Program is establishing consistent processes for monitoring and evaluating the performance of individual and collective restoration actions. The Program collects and reports this information in a manner that will inform future projects and investments, and ultimately improve the performance of the Program. The Program also facilitates increased public access to monitoring and evaluation data by implementing NOAA's Data Sharing Policy for Grants and Cooperative Agreements issued in 2012 which requires that all NOAA grantees share data produced under NOAA grants and cooperative agreements. Program staff works with cooperative agreement recipients to develop a data sharing plan as part of their cooperative agreement award narrative.

d. Funding Sources, Mechanisms, and Eligible Participants

As described in the prior sections, providing financial assistance is a tool that the Program uses to accomplish habitat restoration, complemented by the Program's leadership, coordination, and technical assistance capabilities. Financial assistance is provided competitively through FFO announcements and awarded and managed following the Department of Commerce Grants and Cooperative Agreements Manual and 2 CFR part 200. The Program primarily establishes cooperative agreement awards with selected applicants based on a competitive, technical review process to maximize opportunities for public access to Program resources. In limited circumstances, contracts may also be awarded. All domestic applicants other than individuals may apply for financial assistance. Activities that constitute legally required mitigation or are required by federal, state, or local law or court order are not part of the Program.

e. Reporting

The Program uses a specific reporting format that has received Paperwork Reduction Act clearance. The progress report format assists recipients of Program funding in tracking their progress towards self-defined milestones and performance measures. Progress reports may also include monitoring and evaluation results. The Program-specific form also helps the Program populate a project tracking database, which supports agency-wide performance measure reporting and provides public information through the Restoration Atlas at *www.habitat.noaa.gov/restoration/restorationatlas.*

f. Regulatory Compliance

The Program assists its restoration partners and financial assistance recipients in completing their regulatory compliance responsibilities when possible, and may serve as lead agency for consultation and analysis under the National Environmental Policy Act, Endangered Species Act, National Historic Preservation Act, and other applicable federal laws and regulations. The Program takes a programmatic approach to regulatory compliance when available. A current list of programmatic compliance documents that may be used to fulfill regulatory compliance responsibilities can be found at *http://www.habitat.noaa.gov/funding/applicantresources.html.*

Dated: September 14, 2015.

Samuel D. Rauch III,

Deputy Assistant Administrator for Regulatory Programs, National Marine Fisheries Service.

[FR Doc. 2015–23503 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

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: Coastal and Estuarine Land Conservation, Planning, Protection, or Restoration.

OMB Control Number: 0648–0459.

Form Number(s): None.

Type of Request: Regular (extension of a currently approved information collection).

Number of Respondents: 51.

Average Hours per Response: Plans, 120 hours to develop, 35 hours to revise or update; project application and checklist, 20 hours; semi-annual and annual reporting, 5 hours each.

Burden Hours: 1,410.

Needs and Uses: This request is for extension of a currently approved information collection.

The FY 2002 Commerce, Justice, State Appropriations Act directed the Secretary of Commerce to establish a Coastal and Estuarine Land Conservation Program (CELCP) to protect important coastal and estuarine areas that have significant conservation, recreation, ecological, historical, or aesthetic values, or that are threatened by conversion, and to issue guidelines for this program delineating the criteria for grant awards. The guidelines establish procedures for eligible applicants who choose to participate in the program to use when developing state conservation plans, proposing or soliciting projects under this program, applying for funds, and carrying out projects under this program in a manner that is consistent with the purposes of the program. Guidelines for the CELCP can be found on NOAA's Web site at: *http://www.coast.noaa.gov/czm/landconservation/* or may be obtained upon request via the contact information listed above. The CELCP was reauthorized in under P.L. 111–111, the Omnibus Public Lands Management Act, as a component of the Coastal Zone Management Act. NOAA also has, or is given, additional authority under the Coastal Zone Management Act, annual appropriations or other authorities, to issue funds to coastal states, localities or other recipients for planning, conservation, acquisition, protection, restoration, or construction projects. The required information enables NOAA to implement the CELCP, under its current or future authorization, and facilitate the review of similar projects under different, but related, authorities.

Affected Public: State, local or tribal government; not-for-profit institutions.

Frequency: One time, semi-annually.

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

This information collection request may be viewed at *reginfo.gov.* Follow the instructions to view Department of Commerce collections currently under review by OMB.

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* or fax to (202) 395–5806.

Dated: September 15, 2015.

Sarah Brabson,

NOAA PRA Clearance Officer.

[FR Doc. 2015–23451 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–08–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE199

Gulf of Mexico Fishery Management Council; Public Meeting

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

ACTION: Notice of a public meeting.

SUMMARY: The Gulf of Mexico Fishery Management Council (Council) will hold a four-day meeting to consider actions affecting the Gulf of Mexico fisheries in the exclusive economic zone (EEZ).

DATES: The meeting will be held on Monday, Tuesday, Wednesday, and Thursday, October 5–8, 2015, starting at 8:30 a.m. daily.

ADDRESSES: The meeting will be held at the Hilton Galveston Island Hotel, 5400 Seawall Boulevard, Galveston, TX 77551; telephone: (409) 744–5000; fax: (409) 740–2209.

Council address: Gulf of Mexico Fishery Management Council, 2203 N. Lois Avenue, Suite 1100, Tampa, FL 33607; telephone: (813) 348–1630.

FOR FURTHER INFORMATION CONTACT: Douglas Gregory, Executive Director, Gulf of Mexico Fishery Management Council; telephone: (813) 348–1630.

SUPPLEMENTARY INFORMATION:

Agenda

Monday, October 5, 2015

The Gulf Council will begin with updates and presentations from management committees. The Sustainable Fisheries/Ecosystem Management Committee will review the Integrated Ecosystem Assessment—Management Strategy Evaluation, and receive a presentation on NOAA's Ecosystem Based Fisheries Management Policy. The Joint Administrative Policy & Budget/Personnel Management Committee will review the new Advisory Panels (AP) Staggered Terms, modifications to the standard operating practices and procedures (SOPPs) section discussing AP Appointments, Administrative Committee structure, and review of the Magnuson-Stevens Act Reauthorization Bills. The Mackerel Management Committee will convene after lunch to review the Joint Public Hearing Draft for CMP Amendment 26: Changes in Allocations, Stock Boundaries and Sale Provisions for Gulf of Mexico and Atlantic Migratory Groups of King Mackerel, and an Options Paper for CMP Amendment 28: Separating Permits for Gulf of Mexico and Atlantic Migratory Groups of King Mackerel and Spanish Mackerel. The Data Collection Committee will then review the Public Hearing Draft—Joint Electronic Charter Vessel Reporting Amendment; and the Gulf SEDAR Committee will review the SEDAR Steering Committee meeting and SEDAR Assessment Schedule.

Tuesday, October 6, 2015

The Reef Fish Management Committee will provide updates from the Scientific and Statistical Committee (SSC) and Reef Fish Advisory Panel (AP) meetings. The committee will discuss final action on Framework Action to set Gag Recreational Season and Gag and Black Grouper Minimum Size Limits, review options papers for Amendment to Define Gulf of Mexico Hogfish Stock and set Acceptable Catch Limits (ACL) and Status Determination Criteria and Framework Action to set Mutton Snapper ACL and management measures, and the revised Public Hearing Draft Amendment 39—Regional Management of Recreational Red Snapper. The committee will also review options papers for Adjust Minimum Stock Size Threshold (MSST) and South Florida Management Issues; discussion on the Ad Hoc Private Recreational AP. NMFS will hold a Question and Answer session immediately following the committee.

Wednesday, October 7, 2015

The Reef Fish Management Committee will continue with any remaining agenda items from the previous day. Shrimp Management Committee will review the Public Hearing Draft for Shrimp Amendment 17A—Addressing the Expiration of the Shrimp Permit Moratorium and the Draft Options Paper for Shrimp Amendment 17B—Establishing Optimum Yield, Target Number of Permits, Permit Pool, and Addressing Transit Provisions through Federal Waters.

The Full Council will convene mid-morning with a Call to Order, Announcements and Introductions; Adoption of Agenda and Approval of Minutes. The Council will review and approve the 2016 Committee Appointments. After lunch, the Council will receive presentations on the Southeast Observer Program and the Standardized Reporting Bycatch Methods; and review of Exempted Fishing Permits (EFPs) Applications, if any. The Council will receive Public Comment (2:30 p.m.–5 p.m.) on Final Action on Framework Action to Set Gag Recreational Season and Gag and Black Grouper Minimum Size Limits; followed by open testimony on any other fishery issues or concerns.

Thursday, October 8, 2015

The Council will receive management committee reports from Sustainable Fisheries/Ecosystem, Administrative Policy & Budget/Personnel, Mackerel, Data Collection, Shrimp and SEDAR. Upon returning from lunch, the Council will receive a committee report from the Reef Fish Management Committee; vote on Exempted Fishing Permit (EFP) Applications, if any, and discuss Other Business.

Meeting Adjourns

Although other non-emergency issues not contained in this agenda may come before this Council for discussion, those issues may not be the subjects of formal action during this meeting. 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 that the public has been notified of the Council's intent to take final action to address the emergency.

Special Accommodations

This meeting is physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Kathy Pereira (see **ADDRESSES**) at least 5 days prior to the meeting date.

Dated: September 15, 2015.

Jeffrey N. Lonergan,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–23461 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

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: NMFS Observer Programs' Information That Can be Gathered Only Through Questions.

OMB Control Number: 0648–0593.

Form Number(s): None.

Type of Request: Regular (extension of a currently approved information collection).

Number of Respondents: 3,699.

Average Hours per Response: 51 minutes.

Burden Hours: 27,238.

Needs and Uses: This request is for extension of a currently approved information collection.

The National Oceanic and Atmospheric Administration (NOAA), National Marine Fisheries Service (NMFS) deploys fishery observers on United States (U.S.) commercial fishing vessels and to fish processing plants in order to collect biological and economic data. NMFS has at least one observer program in each of its five Regions. These observer programs provide the most reliable and effective method for obtaining information that is critical for the conservation and management of living marine resources. Observer programs primarily obtain information through direct observations by employees or agents of NMFS; and such observations are not subject to the Paperwork Reduction Act (PRA). However, observer programs also collect the following information that requires clearance under the PRA: (1) Standardized questions of fishing vessel captains/crew or fish processing plant managers/staff, which include gear and performance questions, safety questions, and trip costs, crew size and other economic questions; (2) questions asked by observer program staff/contractors to plan observer deployments; (3) forms that are completed by observers and that fishing vessel captains are asked to review and sign; (4) questionnaires to evaluate observer performance; and (5) a form to certify that a fisherman is the permit holder when requesting observer data from the observer on the vessel. NMFS seeks to renew OMB PRA clearance for these information collections.

The information collected will be used to: (1) Monitor catch and bycatch in federally managed commercial fisheries; (2) understand the population status and trends of fish stocks and protected species, as well as the interactions between them; (3) determine the quantity and distribution of net benefits derived from living marine resources; (4) predict the biological, ecological, and economic impacts of existing management action and proposed management options; and (5) ensure that the observer programs can safely and efficiently collect the information required for the previous four uses. In particular, these biological and economic data collection programs contribute to legally mandated analyses required under the Magnuson-Stevens Fishery Conservation and Management Act (MSA), the Endangered Species Act (ESA), the Marine Mammal Protection Act (MMPA), the National Environmental Policy Act (NEPA), the Regulatory Flexibility Act (RFA), Executive Order 12866 (E.O. 12866), as well as a variety of state statutes. The confidentiality of the data will be protected as required by the MSA, Section 402(b).

Affected Public: Business or other for-profit organizations.

Frequency: On occasion.

Respondent's Obligation: Mandatory.

This information collection request may be viewed at reginfo.gov. Follow the instructions to view Department of Commerce collections currently under review by OMB.

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* or fax to (202) 395–5806.

Dated: September 15, 2015.

Sarah Brabson,

NOAA PRA Clearance Officer.

[FR Doc. 2015–23450 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE194

Fisheries of the South Atlantic; Southeast Data, Assessment, and Review (SEDAR); Public Meeting

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

ACTION: Notice of SEDAR 41 Pre-Assessment webinar for South Atlantic red snapper and gray triggerfish.

SUMMARY: The SEDAR 41 assessments of the South Atlantic stocks of red snapper and gray triggerfish will consist of a series of workshop and webinars: Data Workshops; an Assessment Workshop and webinars; and a Review Workshop. See **SUPPLEMENTARY INFORMATION**.

DATES: A SEDAR 41 Pre-Assessment webinar will be held on Tuesday, October 6, 2015, from 9 a.m. until 1 p.m.

ADDRESSES: The meeting will be held via webinar. The webinar is open to members of the public. Those interested in participating should contact Julia Byrd at SEDAR (see **FOR FURTHER INFORMATION CONTACT**) to request an invitation providing webinar access information. Please request webinar invitations at least 24 hours in advance of each webinar.

SEDAR address: South Atlantic Fishery Management Council, 4055 Faber Place Drive, Suite 201, N. Charleston, SC 29405; *www.sedarweb.org.*

FOR FURTHER INFORMATION CONTACT: Julia Byrd, SEDAR Coordinator, 4055 Faber Place Drive, Suite 201, North Charleston, SC 29405; phone: (843) 571–4366; email: *julia.byrd@safmc.net.*

SUPPLEMENTARY INFORMATION: The Gulf of Mexico, South Atlantic, and Caribbean Fishery Management Councils, in conjunction with NOAA Fisheries and the Atlantic and Gulf States Marine Fisheries Commissions, have implemented the Southeast Data, Assessment and Review (SEDAR) process, a multi-step method for determining the status of fish stocks in the Southeast Region. SEDAR is a three-step process including: (1) Data Workshop; (2) Assessment Process utilizing webinars; and (3) Review Workshop. The product of the Data Workshop is a data report which compiles and evaluates potential datasets and recommends which datasets are appropriate for assessment analyses. The product of the Assessment Process is a stock assessment report which describes the fisheries, evaluates the status of the stock, estimates biological benchmarks, projects future population conditions, and recommends research and monitoring needs. The assessment is independently peer reviewed at the Review Workshop. The product of the Review Workshop is a Summary documenting panel opinions regarding the strengths and weaknesses of the stock assessment and input data. Participants for SEDAR Workshops are appointed by the Gulf of Mexico, South Atlantic, and Caribbean Fishery Management Councils and NOAA Fisheries Southeast Regional Office, Highly Migratory Species Management Division, and Southeast Fisheries Science Center. Participants include: Data collectors and database managers; stock assessment scientists, biologists, and researchers; constituency representatives including fishermen, environmentalists, and non-governmental organizations (NGOs); international experts; and staff of Councils, Commissions, and state and federal agencies.

The items of discussion in the Pre-Assessment webinar are as follows: Participants will finalize data recommendations from the SEDAR 41 Data Workshop and provide early modeling advice.

Although non-emergency issues not contained in this agenda may come before this group for discussion, those issues may not be the subject of formal action during this meeting. Action will be restricted to those issues specifically identified in this notice and any issues arising after publication of this notice that require emergency action under section 305(c) of the Magnuson-Stevens Fishery Conservation and Management Act, provided the public has been notified of the intent to take final action to address the emergency.

Special Accommodations

This meeting is accessible to people with disabilities. Requests for auxiliary aids should be directed to the SAFMC office (see **ADDRESSES**) at least 10 business days prior to the meeting.

Note: The times and sequence specified in this agenda are subject to change.

Authority: 16 U.S.C. 1801 *et seq.*

Dated: September 15, 2015.

Jeffrey N. Lonergan,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–23460 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE188

Endangered and Threatened Species; Take of Anadromous Fish

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

ACTION: Applications for three new scientific research permits and three permit renewals.

SUMMARY: Notice is hereby given that NMFS has received six scientific research permit application requests relating to Pacific salmon and steelhead. The proposed research is intended to increase knowledge of species listed under the Endangered Species Act (ESA) and to help guide management and conservation efforts. The applications may be viewed online at: *https://apps.nmfs.noaa.gov/preview/preview_open_for_comment.cfm.*

DATES: Comments or requests for a public hearing on the applications must be received at the appropriate address or fax number (see **ADDRESSES**) no later than 5 p.m. Pacific standard time on October 19, 2015.

ADDRESSES: Written comments on the applications should be sent to the Protected Resources Division, NMFS, 1201 NE Lloyd Blvd., Suite 1100, Portland, OR 97232–1274. Comments may also be sent via fax to 503–230–5441 or by email to *nmfs.nwr.apps@noaa.gov* (include the permit number in the subject line of the fax or email).

FOR FURTHER INFORMATION CONTACT: Rob Clapp, Portland, OR (ph.: 503–231–2314), Fax: 503–230–5441, email: *Robert.Clapp@noaa.gov*). Permit application instructions are available from the address above, or online at *https://apps.nmfs.noaa.gov.*

SUPPLEMENTARY INFORMATION:

Species Covered in This Notice

The following listed species are covered in this notice:

Chinook salmon (*Oncorhynchus tshawytscha*): Threatened Lower Columbia River (LCR); threatened Puget Sound (PS); threatened Snake River (SR) fall-run; threatened SR spring/summer-run (spr/sum); endangered Upper Columbia River (UCR) spring-run; threatened Upper Willamette River (UWR).

Steelhead (*O. mykiss*): Threatened UCR; Threatened SR; threatened middle Columbia River (MCR); threatened LCR; threatened PS; threatened UWR.

Sockeye salmon (*O. nerka*): Endangered SR.

Chum salmon (*O. keta*): Threatened Columbia River (CR).

Coho salmon (*O. kisutch*): Threatened LCR; threatened Oregon Coast (OC).

Authority

Scientific research permits are issued in accordance with section 10(a)(1)(A) of the ESA (16 U.S.C. 1531 *et. seq*) and regulations governing listed fish and wildlife permits (50 CFR parts 222–226). NMFS issues permits based on findings that such permits: (1) Are applied for in good faith; (2) if granted and exercised, would not operate to the disadvantage of the listed species that are the subject of the permit; and (3) are consistent with the purposes and policy of section 2 of the ESA. The authority to take listed species is subject to conditions set forth in the permits.

Anyone requesting a hearing on an application listed in this notice should set out the specific reasons why a hearing on that application would be appropriate (see **ADDRESSES**). Such hearings are held at the discretion of the Assistant Administrator for Fisheries, NMFS.

Applications Received

Permit 1336–7R

Port Blakely Farms (PBF) is seeking to renew its permit to take juvenile LCR Chinook salmon, UWR Chinook salmon, PS Chinook salmon, LCR coho salmon, LCR steelhead, UWR steelhead, and PS steelhead in headwater streams in western Oregon and Washington. The purpose of the research is to evaluate factors limiting fish distribution and water quality in streams that cross land owned by PBF. The research would benefit listed salmonids by producing data to be used in conserving and restoring critical habitat. The researchers propose to capture (using backpack electrofishing and dipnetting), handle, and release juvenile fish. The PBF researchers do not intend to kill any fish being captured, but some may die as an unintentional result of the research activities.

Permit 15486–2R

West Fork Environmental is seeking to renew its permit to capture and handle juvenile UCR Chinook salmon, LCR Chinook salmon, UWR Chinook salmon, PS Chinook salmon, LCR coho salmon, OC coho salmon, UCR steelhead, LCR steelhead, UWR steelhead, and PS steelhead during the course of headwater stream surveys over wide parts of Oregon and Washington. The purpose of the research is to provide owners of industrial forest lands and state lands managers with accurate maps of where threatened and endangered salmonids are found on state and industrial forest lands. The work would benefit the salmon and steelhead by helping land managers plan and carry out their activities in ways that would have the smallest effect possible on the listed fish. The fish would be captured using backpack electrofishing equipment and released without tagging or even handling more than is necessary to ensure that they have recovered from the effects of being captured. The West Fork Environmental researchers do not intend to kill any listed salmonids, but a small number may die as an unintended result of the activities.

Permit 16784–2R

Hart Crowser, Inc. is seeking to renew a one-year scientific research permit to take juvenile SR fall Chinook salmon, SR spr/sum Chinook salmon, UCR Chinook salmon, UWR Chinook salmon, LCR Chinook salmon, CR chum salmon, LCR coho, SR sockeye salmon, SR steelhead, UCR steelhead, MCR steelhead, LCR steelhead, and UWR steelhead. The objective of the research is to study the degree to which juvenile salmonids may be getting stranded by ship wakes along the lower Columbia River between river miles 21 and 102. The researchers would investigate the potential for stranding at approximately 24 ''high risk'' sites. The researchers would also evaluate whether the strategic placement of dredged material could reduce the risk of stranding. The research would benefit the listed species by helping river managers determine the likelihood of juvenile stranding along the lower river and investigate potential means for reducing it. Hart Crowser, Inc. would use beach seines to capture, handle, and release juvenile fish. Researchers may also collect stranded fish and return them to the river. Hart Crowser, Inc. does not intend to kill any of the fish being captured but a small number may die as an unintended result of the activities.

Permit 19587

The Columbia River Estuary Study (CREST) is requesting a three-year scientific research permit to take LCR Chinook salmon, CR chum salmon, and LCR coho salmon. The objective of the research is to study the effectiveness of habitat restoration in Meglar Creek, Washington. The research would evaluate fish passage and habitat use in Meglar Creek and the Columbia River nearshore environment at the mouth of Meglar Creek. The CREST researchers would capture fish with a trap net. A portion of the juvenile Chinook and coho salmon would be anesthetized and tagged with passive integrated transponder tags (PIT-tags). The research would benefit listed salmonids by determining how effectively currently altered habitats support salmonids and using that information to guide future habitat modifications. CREST does not intend to kill any listed fish but a small number may die as an unintended result of the research activities.

Permit 19690

The Idaho Department of Fish and Game (IDFG) is seeking a five-year permit to take adult SR spr/sum Chinook, SR sockeye, and SR steelhead at a location approximately one mile upstream from the confluence of the Lemhi and Salmon Rivers in Idaho. Under the permit, they would trap adult Chinook and steelhead at a temporary weir, measure and tag them with PIT-tags, and monitor their movements in the Lemhi Valley with the purpose of determining the animals' response to habitat improvements throughout the subbasin. All adult sockeye salmon captured at the weir would simply be handled and released without being tagged. The weir would operate in 12-hour increments (checked at least twice daily), and all fish to be tagged would be anesthetized before the process, and allowed to recover afterwards; they would then be released back to the river upstream from the weir. The researchers would also collect scale and tissue samples from a number of fish for DNA analysis. The research is intended to form an integral part of an ongoing program that intensively monitors a number of ecological parameters in the Lemhi watershed. The weir operation would allow greater resolution of both adult return numbers and fish movement in the area, and it would feed that data into the information stream being generated by the overall program. The research would benefit the fish by providing new information that managers can use to (1) evaluate and monitor steelhead and Chinook status in the region, and (2) design and deploy increasingly effective habitat restoration actions throughout the fishes' range. The researchers do not intend to kill any of the listed fish, but a few may die as an inadvertent result of the planned activities.

Permit 19741

The Yakama Nation is seeking a five-year permit to annually take juvenile, natural MCR steelhead during the course of a research project designed to assess their current abundance in the Rock Creek watershed in south central Washington. Under the permit, the researchers would employ backpack electrofishing to capture a number of juvenile MCR steelhead. Some of those fish would be tagged with PIT-tags, and some would be tissue-sampled, but most would simply be handled and released. The researchers would work primarily in five reference areas (reaches) and they would use mark/recapture techniques to study juvenile development and movement in Rock Creek. They would also conduct some boat electrofishing in the inundated pool downstream from the research area in Rock Creek—primarily to look at predator abundance. In addition, the researchers would take tissue samples from dead adults during spawning ground surveys. The purpose of the research is to assess the current distribution and relative abundance of MCR steelhead in selected portions of Rock Creek. That information would be integrated with information being collected on other ecological parameters and the researches would use that information as a whole to determine species status in the system and evaluate the effectiveness of several habitat restoration actions that have been going on there for a number of years. This research would benefit listed steelhead in that it would be used by fish managers such as the Rock Creek Subbasin Recovery Planning Group to prioritize to plan restoration, protection, and recovery actions for Rock Creek steelhead.

This notice is provided pursuant to section 10(c) of the ESA. NMFS will evaluate the applications, associated documents, and comments submitted to determine whether the applications meet the requirements of section 10(a) of the ESA and Federal regulations. The final permit decisions will not be made until after the end of the 30-day comment period. NMFS will publish notice of its final action in the **Federal Register**.

Dated: September 15, 2015.

Angela Somma,

Chief, Endangered Species Division, Office of Protected Resources, National Marine Fisheries Service.

[FR Doc. 2015–23454 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

DEPARTMENT OF COMMERCE

National Oceanic and Atmospheric Administration

RIN 0648–XE192

North Pacific 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 North Pacific Fishery Management Council (Council) and its advisory committees will meet Monday, October 5, 2015, through Tuesday, October 13, 2015.

DATES: The meetings will be held Monday, October 5, 2015 through Tuesday, October 13, 2015. See **SUPPLEMENTARY INFORMATION** for specific dates.

ADDRESSES: The meetings will be held at the Anchorage Hilton Hotel, 500 W. 3rd Ave., Anchorage, AK 99501. See **SUPPLEMENTARY INFORMATION** for specific locations.

Council address: North Pacific Fishery Management Council, 605 W. 4th Ave., Suite 306, Anchorage, AK 99501–2252; telephone: (907) 271–2809.

FOR FURTHER INFORMATION CONTACT: David Witherell, Council staff; telephone: (907) 271–2809.

SUPPLEMENTARY INFORMATION: The Council will begin its plenary session at 8 a.m. in the Aleutian Room on Wednesday, October 7, continuing through Tuesday, October 13, 2015. The Scientific Statistical Committee (SSC) will begin at 8 a.m. in the King Salmon/Iliamna Room on Monday, October 5 and continue through Wednesday, October 7, 2015. The Council's Advisory Panel (AP) will begin at 8 a.m. in the Dillingham/Katmai Room on Tuesday, October 6, and continue through Saturday, October 10, 2015. The Enforcement Committee will meet on Tuesday, October 6, 2015 (room and time to be determined). The Legislative Committee will meet on Tuesday, October 6, 2015, from 2 p.m. to 5 p.m. (room to be determined).

Agenda

Monday, October 5, 2015 Through Tuesday, October 13, 2015

Council Plenary Session: The agenda for the Council's plenary session will include the following issues. The Council may take appropriate action on any of the issues identified.

(1) Executive Director's Report (including Halibut Management Framework Outline, and Halibut Deck Sorting)
(2) NMFS Management Report (including update on non-fishing habitat issues, litigation updates)
(3) ADF&G Report (including BOF proposals)
(4) USCG Report
(5) USFWS Report
(6) Protected Species Report
(7) BSAI Crab SAFE/Specifications for 6 stocks
(8) Proposed Groundfish Harvest Specifications
(9) Pribilof Canyon Corals: Receive Report/Next Steps
(10) AI Pacific cod Allocation: Final Action
(11) EM Workgroup recommendation for 2016 Pre-implementation
(12) Observer Program 2016 Annual Deployment Plan: Review
(13) Observer Coverage on BSAI Trawl CVs: Initial Review
(14) GOA Trawl Bycatch Management: Review Paper
(15) 100% Observer Coverage for GOA Trawl: Discussion paper
(16) GOA Salmon PSC Reapportionment: Preliminary Review
(17) WAI Golden King Crab Partial Offloads: Final Action

The Agenda is subject to change, and the latest version will be posted at *http://www.npfmc.org/.*

Although non-emergency issues not contained in this agenda may come before these groups for discussion, those issues may not be the subject of formal action during these meetings. 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.

Special Accommodations

These meetings are physically accessible to people with disabilities. Requests for sign language interpretation or other auxiliary aids should be directed to Shannon Gleason at (907) 271–2809 at least 7 working days prior to the meeting date.

Dated: September 15, 2015.

Jeffrey N. Lonergan,

Acting Deputy Director, Office of Sustainable Fisheries, National Marine Fisheries Service.

[FR Doc. 2015–23459 Filed 9–17–15; 8:45 am]

BILLING CODE 3510–22–P

COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

Procurement List; Additions and Deletions

AGENCY: Committee for Purchase from People Who are Blind or Severely Disabled.

ACTION: Additions to and deletions from the Procurement List.

SUMMARY: This action adds products and a service to the Procurement List that will be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities, and deletes services from the Procurement List previously furnished by such agencies.

DATES: *Effective Date:* 10/19/2015.

ADDRESSES: Committee for Purchase From People Who Are Blind or Severely Disabled, 1401 S. Clark Street, Suite 715, Arlington, Virginia 22202–4149.

FOR FURTHER INFORMATION CONTACT: Barry S. Lineback, Telephone: (703) 603–7740, Fax: (703) 603–0655, or email *CMTEFedReg@AbilityOne.gov.*

SUPPLEMENTARY INFORMATION:

Additions

On 6/26/2015 (80 FR 36773–36774) and 8/4/2015 (80 FR 46250), the Committee for Purchase From People Who Are Blind or Severely Disabled published notices of proposed additions to the Procurement List.

After consideration of the material presented to it concerning capability of qualified nonprofit agencies to provide the products and service and impact of the additions on the current or most recent contractors, the Committee has determined that the products and service listed below are suitable for procurement by the Federal Government under 41 U.S.C. 8501–8506 and 41 CFR 51–2.4.

Regulatory Flexibility Act Certification

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action will not result in any additional reporting, recordkeeping or other compliance requirements for small entities other than the small organizations that will furnish the products and service to the Government.
2. The action will result in authorizing small entities to furnish the products and service to the Government.
3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 8501–8506) in connection with the products and service proposed for addition to the Procurement List.

End of Certification

Accordingly, the following products and service are added to the Procurement List:

Products

NSN(s)—Product Name(s):
7930–00–NIB–0717—Floor Finish/Sealer, Black, Water-Based, Slip-Resistant, Asphalt Floors, 5 Gal. Can
7930–00–NIB–0675—Floor Finish/Sealer, Black, Water-Based, Slip-Resistant, Asphalt Floors, 4/1 Gal. Bottles
Mandatory Source(s) of Supply: Lighthouse for the Blind of Houston, Houston, TX
Mandatory Purchase For: Broad Government Requirement
Contracting Activity: General Services Administration, Fort Worth, TX
Distribution: B-List

Service

Service Type: Janitorial and Related Service
Service Mandatory For: U.S. Customs and Border Protection; 1 La Puntilla Street; San Juan, PR
Mandatory Source(s) of Supply: The Corporate Source, Inc., New York, NY
Contracting Activity: U.S. Customs and Border Protection, Border Enforcement Contracting Division

Deletions

On 8/7/2015 (80 FR 47475) and 9/4/2015 (80 FR 53501–53502), the Committee for Purchase From People Who Are Blind or Severely Disabled published notices of proposed deletions from the Procurement List.

After consideration of the relevant matter presented, the Committee has determined that the services listed below are no longer suitable for procurement by the Federal Government under 41 U.S.C. 8501–8506 and 41 CFR 51–2.4.

Regulatory Flexibility Act Certification

I certify that the following action will not have a significant impact on a substantial number of small entities. The major factors considered for this certification were:

1. The action will not result in additional reporting, recordkeeping or other compliance requirements for small entities.
2. The action may result in authorizing small entities to provide the services to the Government.
3. There are no known regulatory alternatives which would accomplish the objectives of the Javits-Wagner-O'Day Act (41 U.S.C. 8501–8506) in connection with the services deleted from the Procurement List.

End of Certification

Accordingly, the following services are deleted from the Procurement List:

Services

Service Type: Rebuilding Auto Components Service
Service Mandatory For: Location Unknown
Mandatory Source(s) of Supply: Federation Employment and Guidance Service, Inc., New York, NY
Contracting Activity: General Services Administration, FPDS Agency Coordinator
Service Type: Warehousing Service
Service Mandatory For: Barbers Point Naval Air Station, Barbers Point, HI
Mandatory Source(s) of Supply: Trace, Inc., Boise, ID
Contracting Activity: Defense Commissary Agency

Barry S. Lineback,
Director, Business Operations.

[FR Doc. 2015–23442 Filed 9–17–15; 8:45 am]

BILLING CODE 6353–01–P

COMMITTEE FOR PURCHASE FROM PEOPLE WHO ARE BLIND OR SEVERELY DISABLED

Procurement List; Proposed Additions

AGENCY: Committee for Purchase from People Who are Blind or Severely Disabled.

ACTION: Proposed additions to the Procurement List.

SUMMARY: The Committee is proposing to add products to the Procurement List that will be furnished by nonprofit agencies employing persons who are blind or have other severe disabilities.

Comments Must Be Received On Or Before: 10/19/2015.

ADDRESSES: Committee for Purchase From People Who Are Blind or Severely Disabled, 1401 S. Clark Street, Suite 715, Arlington, Virginia 22202–4149.

FOR FURTHER INFORMATION OR TO SUBMIT COMMENTS CONTACT: Barry S. Lineback, Telephone: (703) 603–7740, Fax: (703) 603–0655, or email *CMTEFedReg@AbilityOne.gov.*

SUPPLEMENTARY INFORMATION: This notice is published pursuant to 41 U.S.C. 8503 (a)(2) and 41 CFR 51–2.3. Its purpose is to provide interested persons an opportunity to submit comments on the proposed actions.

Additions

If the Committee approves the proposed additions, the entities of the Federal Government identified in this notice will be required to procure the products listed below from nonprofit agencies employing people who are blind or have other severe disabilities.

The following products are proposed for addition to the Procurement List for production by the nonprofit agency listed:

Products

NSN(s)—Product Name(s): 1670–01–F05–1124–T–11R Parachute Insert, Army
Mandatory Source(s) of Supply: Chautauqua County Chapter, NYSARC, Jamestown, NY
NSN(s)—Product Name(s): 8415–01–644–9620–Gaiter, FREE, Army, Army Tan
Mandatory Source(s) of Supply: NYSARC, Inc., Seneca-Cayuga Counties Chapter, Waterloo, NY
Mandatory Purchase For: 100% of the requirement of the US Army
Contracting Activity: Dept of the Army, W6QK ACC–APG Natick, Natick, MA
Distribution: C-List

Barry S. Lineback,
Director, Business Operations.

[FR Doc. 2015–23441 Filed 9–17–15; 8:45 am]

BILLING CODE 6353–01–P

DEFENSE NUCLEAR FACILITIES SAFETY BOARD

Sunshine Act Notice

AGENCY: Defense Nuclear Facilities Safety Board.

ACTION: Meeting cancellation.

SUMMARY: The Defense Nuclear Facilities Safety Board (Board) published a notice in the **Federal Register** of July 27, 2015, (80 FR 44335), concerning a two-session public hearing and open meeting on August 26, 2015, at the Three Rivers Convention Center, 7016 West Grandridge Boulevard, Kennewick, Washington 99352. The Board corrected that notice in the **Federal Register** of August 28, 2015, (80 FR 52265), by postponing the Session II open meeting and supplementing the Session I hearing. The Board has now voted to cancel, in lieu of postponing, the Session II open meeting portion of the proceeding. The vote record for the cancellation of the open meeting will be posted on the Board's public Web site.

FOR FURTHER INFORMATION CONTACT: Mark Welch, General Manager, Defense Nuclear Facilities Safety Board, 625 Indiana Avenue NW., Suite 700, Washington, DC 20004–2901, (800) 788–4016. This is a toll-free number.

Dated: September 15, 2015.

Joyce L. Connery,
Chairman.

[FR Doc. 2015–23547 Filed 9–16–15; 11:15 am]

BILLING CODE 3670–01–P

DEPARTMENT OF ENERGY

Hawaii Clean Energy Final Programmatic Environmental Impact Statement

AGENCY: U.S. Department of Energy.

ACTION: Notice of availability.

SUMMARY: The U.S. Department of Energy (DOE) announces the availability of the *Hawaii Clean Energy Final Programmatic Environmental Impact Statement* (Hawaii Clean Energy Final PEIS or Final PEIS) (DOE/EIS–0459). The PEIS, which is not required under the National Environmental Policy Act (NEPA), evaluates the potential environmental impacts associated with 31 energy efficiency activities and renewable energy technologies that could be implemented to assist the State of Hawaii in meeting the goals established under the Hawaii Clean Energy Initiative (HCEI).

ADDRESSES: The Department encourages interested parties to access the Final PEIS electronically. It is posted at *http://hawaiicleanenergypeis.com* and *http://energy.gov/nepa/eis-0459-hawaii-clean-energy-programmatic-environmental-impact-statement.*

CDs and printed copies are available for viewing at:

- Hawaii State Library, 478 South King Street, Honolulu, HI 96813
- Lanai Public and School Library, 555 Fraser Ave., Lanai City, HI 96763
- Wailuku Public Library, 251 High Street, Wailuku, HI 96793

• Molokai Public Library, 15 Ala Malama, Kaunakakai, HI 96748
• Hilo Public Library, 300 Waianuenue Ave., Hilo, HI 96720.
• Kailua-Kona Public Library, 75–138 Hualalai Road, Kailua-Kona, HI 96740.
• Lihue Public Library, 4344 Hardy Street, Lihue, HI 96766

The Hawaii State Energy Office will provide a printed copy of the Summary or complete Final PEIS to individuals who cannot access the document online or from a CD. If a printed copy is required, send an email request to *energyoffice@dbedt.hawaii.gov,* or call 808–587–3807.

FOR FURTHER INFORMATION CONTACT: For additional information on the Hawaii Clean Energy Final PEIS, contact Dr. Jane Summerson at *hawaiicleanenergypeis@ee.doe.gov or the Hawaii State Energy Office at* 808–587–3807. For general information regarding the DOE NEPA process, contact: Ms. Carol M. Borgstrom, Director, Office of NEPA Policy and Compliance (GC–54), U.S. Department of Energy, 1000 Independence Ave. SW., Washington, DC 20585; email to *askNEPA@hq.doe.gov,* call 202–586–4600, or leave a message at 800–472–2756.

SUPPLEMENTARY INFORMATION:

Background

DOE and Hawaii entered into a Memorandum of Understanding (MOU) in January 2008 that established a long-term partnership to transform the way in which energy efficiency and renewable energy resources are planned and used in the State. The MOU established working groups to address key sectors of the energy economy (*e.g.,* electricity, end-use efficiency, transportation, and fuels), which led to the establishment of the HCEI. When it was established, HCEI set a goal of meeting 70 percent of Hawaii's energy needs by 2030 through energy efficiency and renewable energy (collectively ''clean energy''). DOE has helped advance Hawaii's clean energy goals by providing technical research and analysis, staff involvement, and funding. In September 2014, DOE and the State of Hawaii signed another MOU to reaffirm their commitment to the HCEI.

Purpose and Need for Agency Action

The purpose and need for DOE's action is based on the 2008 and 2014 MOUs with the State of Hawaii that established the long-term HCEI partnership. Consistent with these MOUs, DOE's purpose and need is to support the State of Hawaii in its efforts to meet 70 percent of the State's energy needs by 2030 through clean energy.

DOE's primary purpose in preparing this PEIS, which is not required under NEPA, is to provide information to the public, Federal and State agencies, and future energy developers on the potential environmental impacts of a wide range of energy efficiency activities and renewable energy technologies that could be used to support the HCEI. This environmental information could be used by decisionmakers, developers, and regulators in determining the best activities and technologies to meet future energy needs. The public could use this PEIS to better understand the types of potential impacts associated with the various technologies.

Proposed Action

DOE's Proposed Action is to develop guidance that it can use in making decisions about future funding or other actions to support the State of Hawaii in achieving the HCEI's goal.

For the Hawaii Clean Energy PEIS, DOE and the State of Hawaii identified 31 clean energy technologies and activities associated with potential future actions and grouped them into five clean energy categories:

• Energy efficiency,
• Distributed renewable energy technologies,
• Utility-scale renewable energy technologies,
• Alternative vehicle fuels and modes, and
• Electrical transmission and distribution.

For each activity or technology, the PEIS identifies potential impacts to 17 environmental resource areas and potential best management practices that could be used to minimize or prevent those potential environmental impacts.

On April 18, 2014, DOE published in the **Federal Register** its notice of availability for the Hawaii Clean Energy Draft PEIS (79 FR 21909). DOE's NOA invited the public to comment on the Draft PEIS during a 90-day period that ended on July 17, 2014. DOE held public hearings in Lihue, Kailua-Kona, Hilo, Kahului, Kaunakakai, Lanai City, Honolulu, and Kaneohe from May 12 to May 22, 2014. Comments received during the public comment period were addressed in a ''Comment-Response Document,'' which is Chapter 9 of the Final PEIS. Comments received after the close of the comment period also were considered. DOE does not expect to issue a record of decision.

Issued in Washington, DC, September 10, 2015.

Meghan M. Conklin,

Deputy Assistant Secretary, National Electricity Delivery Division, Office of Electricity Delivery and Reliability, Department of Energy.

[FR Doc. 2015–23414 Filed 9–17–15; 8:45 am]

BILLING CODE 6450–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Project No. 2211–008]

Duke Energy Indiana, Inc.; Duke Energy Indiana, LLC; Notice of Application for Transfer of License and Soliciting Comments, Motions To Intervene, and Protests

On September 2, 2015, Duke Energy Indiana, Inc. (transferor) filed an application for transfer of license of the Markland Hydroelectric Project, FERC No. 2211 to Duke Energy Indiana, LLC (transferee). The project is located on the Ohio River in Switzerland County, Indiana.

Duke Energy Indiana, Inc. is an indirect subsidiary of Duke Energy Corporation. To modernize and simplify Duke Energy Corporation's structure, Duke Energy Indiana, Inc. intends to convert to an LLC, (Duke Energy Indiana, LLC). Duke Energy Indiana, Inc. seeks Commission approval to transfer the license for the Markland Hydroelectric Project to Duke Energy Indiana, LLC in association with the conversion, effective on the date Duke Energy Indiana, LLC submits certified copies of its articles of conversion, plan of conversion, and limited liability company operating agreement to the Commission.

Applicant Contact: For Applicant: Mr. Garry S. Rice, Deputy General Counsel, Duke Energy Corporation, 550 South Tryon Street, Mail Code DEC45A, Charlotte, NC 28202, Phone: 704–382–8111, Email: *Garry.Rice@duke-energy.com* and John A. Whittaker, IV, Winston & Strawn LLP, 1700 K Street NW., Washington, DC 20006–3817, Phone: 202–282–5766, Email: *jwhittaker@wiston.com.*

FERC Contact: Patricia W. Gillis, (202) 502–8735.

Deadline for filing comments, motions to intervene, and protests: 30 days from the date that the Commission issues this notice. The Commission strongly encourages electronic filing. Please file motions to intervene, comments, and protests using the Commission's eFiling system at *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,* (866) 208–3676 (toll free), or (202) 502–8659 (TTY). In lieu of electronic filing, please send a paper copy to: Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Washington, DC 20426. The first page of any filing should include docket number P–2211–008.

Dated: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23424 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Notice of Commission Staff Attendance

The Federal Energy Regulatory Commission (Commission) hereby gives notice that members of the Commission's staff may attend the following meeting related to the transmission planning activities of the New York Independent System Operator, Inc.

The New York Independent System Operator, Inc. Electric System Planning Working Group Meeting

September 24, 2015, 10:00 a.m.–4:00 p.m. (EST)

The above-referenced meeting will be via Web conference and teleconference.

The above-referenced meeting is open to stakeholders.

Further information may be found at: *http://www.nyiso.com/public/markets_operations/services/planning/index.jsp.*

The discussions at the meeting described above may address matters at issue in the following proceedings:

New York Independent System Operator, Inc., Docket No. ER13–102.
ISO New England Inc., et al., Docket Nos. ER13–1957, et al.
ISO New England Inc., Docket Nos. ER13–193 and ER13–196.
New York Independent System Operator, Inc., Docket No. ER14–2059.
New York Power Authority, Docket No. ER15–2012.
New York Transco, LLC, Docket No. ER15–572.

For more information, contact James Eason, Office of Energy Market Regulation, Federal Energy Regulatory Commission at (202) 502–8622 or *James.Eason@ferc.gov.*

Dated: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23423 Filed 9–17–15; 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: ER15–1293–002.
Applicants: Southwest Power Pool, Inc.
Description: Compliance filing: Complaince Revisions in Docket No. ER15–1293—Attachment AE to be effective 5/15/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5038.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–1405–001.
Applicants: The Empire District Electric Company.
Description: Compliance filing: Compliance Filing re Settlement to be effective 6/1/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5076.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–1918–001.
Applicants: Southwest Power Pool, Inc.
Description: Compliance filing: Compliance Filing in ER15–1918—Transmission Owner Selection Process Revisions to be effective 8/15/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5091.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2219–001.
Applicants: EONY Generation Limited.
Description: Compliance filing: Amendment to 20 to be effective 7/17/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5101.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2376–001.
Applicants: Energy Power Investment Company, LLC.
Description: Tariff Amendment: Supplement to MBR application to be effective 9/3/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5071.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2641–000.
Applicants: ISO New England Inc., New England Power Pool Participants Committee, Eversource Energy Service Company (as agent).
Description: § 205(d) Rate Filing: CTS to be effective 12/31/9998.
Filed Date: 9/10/15.
Accession Number: 20150910–5150.
Comments Due: 5 p.m. ET 10/1/15.

Docket Numbers: ER15–2642–000.
Applicants: California Independent System Operator Corporation.
Description: § 205(d) Rate Filing: 2015–09–10_Planning Coordinator Agreement with CCSF and CEII Request to be effective 11/10/2015.
Filed Date: 9/10/15.
Accession Number: 20150910–5151.
Comments Due: 5 p.m. ET 10/1/15.

Docket Numbers: ER15–2643–000.
Applicants: Northern Indiana Public Service Company.
Description: § 205(d) Rate Filing: Filing of a CIAC Agreement to be effective 11/10/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5088.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2644–000.
Applicants: Duke Energy Florida, LLC.
Description: § 205(d) Rate Filing: Florida—Southern TIAA Concurrence Filing to be effective 10/23/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5105.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2645–000.
Applicants: R.E. Ginna Nuclear Power Plant, LLC.
Description: § 205(d) Rate Filing: 2015 normal Sep to be effective 9/11/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5122.
Comments Due: 5 p.m. ET 10/2/15.

Docket Numbers: ER15–2646–000.
Applicants: Southwest Power Pool, Inc.
Description: § 205(d) Rate Filing: 2158R5 AECC NITSA and NOA Notice of Cancellation to be effective 7/1/2015.
Filed Date: 9/11/15.
Accession Number: 20150911–5134.
Comments Due: 5 p.m. ET 10/2/15.

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 p.m. 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: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23421 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EF15–10–000]

Western Area Power Administration; Notice of Filing

Take notice that on September 3, 2015 the Western Area Power Administration submitted a tariff filing: Rate Adjustment for Salt Lake City Area Integrated Projects Firm Power (Colorado River Storage Project Transmission and Ancillary Services—Rate Order No. WAPA–169) to be effective October 1, 2015.

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. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

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 5 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: 5:00 p.m. Eastern Time on October 5, 2015.

Dated: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23428 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP15–95–000]

Columbia Gas Transmission, LLC; Notice of Availability of the Environmental Assessment for the Proposed Tri-County Bare Steel Replacement Project

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Tri-County Bare Steel Replacement Project, proposed by Columbia Gas Transmission, LLC (Columbia) in the above-referenced docket. Columbia requests authorization to replace about 34 miles of bare steel pipe within Columbia's existing Line 1570 pipeline in three replacement segments spanning Allegheny, Washington, and Greene Counties (*i.e.,* the Tri-County), Pennsylvania. The Project is part of Columbia's modernization program to replace segments of existing, aging, infrastructure in order to improve the safety of its pipeline system and increase service reliability.

The EA assesses the potential environmental effects of the construction and operation of the Tri-County Bare Steel Replacement Project in accordance with the requirements of the National Environmental Policy Act (NEPA). The FERC staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

The proposed Tri-County Bare Steel Replacement Project includes replacing 34 miles of 20-inch-diameter bare steel piping with coated steel pipeline at the following locations:

- Segment 1: replace approximately 14 miles with 14.9 miles from the Hero Valve to Waynesburg Compressor Station in Greene County.
- Segment 2: replace approximately 8 miles with 10.7 miles from the Redd Farm Station to Sharp Farm Station in Washington County.
- Segment 3: replace approximately 12 miles with 11.9 miles from the Sharp Farm Station in Washington County to the Walker Farm Station in Washington and Allegheny Counties.

Total construction length with the incorporation of minor reroutes is approximately 34 miles of 20-inch-diameter pipe. The pipeline would also include associated appurtenant facilities including bi-directional pig launcher/receivers, cathodic protection, main line valves, and taps.

The FERC staff mailed copies of the EA to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; newspapers and libraries in the project area; and parties to this proceeding. In addition, the EA is available for public viewing on the FERC's Web site (*www.ferc.gov*) using the eLibrary link. A limited number of copies of the EA are available for distribution and public inspection at: Federal Energy Regulatory Commission, Public Reference Room, 888 First Street NE., Room 2A, Washington, DC 20426, (202) 502–8371.

Any person wishing to comment on the EA may do so. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that the Commission has the opportunity to consider your comments prior to making its decision on this project, it is important that we receive your comments in Washington, DC on or before October 14, 2015.

For your convenience, there are three methods you can use to file your comments with the Commission. In all instances, please reference the project docket number (CP15–95–000) with your submission. The Commission encourages electronic filing of comments and has expert staff available to assist you at 202–502–8258 or *efiling@ferc.gov.*

(1) You can file your comments electronically using the *eComment* feature located on the Commission's Web site (*www.ferc.gov*) under the link to *Documents and Filings.* This is an

easy method for submitting brief, text-only comments on a project;

(2) You can also file your comments electronically using the *eFiling* feature on the Commission's Web site (*www.ferc.gov*) under the link to *Documents and Filings*. With eFiling, you can provide comments in a variety of formats by attaching them as a file with your submission. New eFiling users must first create an account by clicking on ''*eRegister*.'' You must select the type of filing you are making. If you are filing a comment on a particular project, please select ''Comment on a Filing''; or

(3) You can file a paper copy of your comments by mailing them to the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Room 1A, Washington, DC 20426.

Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214).[1] Only intervenors have the right to seek rehearing of the Commission's decision. The Commission grants affected landowners and others with environmental concerns intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which no other party can adequately represent. Simply filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered.

Additional information about the project is available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC Web site (*www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, click on ''General Search,'' and enter the docket number excluding the last three digits in the Docket Number field (*i.e.,* CP15–95). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or toll free at (866) 208–3676, or for TTY, contact (202) 502–8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription that allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to *www.ferc.gov/docs-filing/esubscription.asp.*

[1] See the previous discussion on the methods for filing comments.

Dated: September 14, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23426 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

Staff Notice of Alleged Violations

Take notice [1] that in a nonpublic investigation pursuant to 18 CFR part 1b, the staff of the Office of Enforcement of the Federal Energy Regulatory Commission has preliminarily determined that Coaltrain Energy LP; its co-owners Peter Jones and Shawn Sheehan; traders Robert Jones, Jeff Miller, and Jack Wells; and analyst Adam Hughes violated the Commission's Anti-Manipulation Rule, 18 CFR 1c.2 (2015), by devising and executing a scheme involving manipulative Up-To Congestion trading in PJM Regional Transmission Organization between June and September 2010. The Office of Enforcement has also preliminarily determined that Coaltrain violated 18 CFR 35.41(b) (2015) by making false statements and omitting material information during the investigation.

During the period of interest, Peter Jones and Shawn Sheehan were the principal owners of Coaltrain, and they along with Jeff Miller, Robert Jones, Jack Wells, and Adam Hughes devised and implemented the relevant trades in PJM. Staff alleges that the individuals (on behalf of Coaltrain) planned and executed Up-To Congestion transactions in PJM that were designed to falsely appear to be spread trades but that were in fact a vehicle to collect certain payments (called ''Marginal Loss Surplus Allocation,'' or MLSA) from PJM. Staff alleges that through these trades, Coaltrain sought not to profit from changes in price spreads but rather to profit by clearing large volumes of Up-To Congestion transactions with the goal of collecting MLSA.

Staff further alleges that during the investigation, Peter Jones, Shawn Sheehan, and their agents (on behalf of Coaltrain) made false statements and omitted material information in responding to deposition questions and data requests.

This Notice does not confer a right on third parties to intervene in the investigation or any other right with respect to the investigation.

[1] *Enforcement of Statutes, Regulations, and Orders,* 129 FERC ¶ 61,247 (2009), *order on reh'g,* 134 FERC ¶ 61,054 (2011).

Dated: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23429 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP15–14–001]

Texas Gas Transmission, LLC; Notice of Availability of the Environmental Assessment for the Proposed Southern Indiana Market Lateral Project

The staff of the Federal Energy Regulatory Commission (FERC or Commission) has prepared an environmental assessment (EA) for the Southern Indiana Market Lateral Project, proposed by Texas Gas Transmission, LLC (Texas Gas) in the above-referenced docket. Texas Gas requests authorization to deliver approximately 53.5 million standard cubic feet per day of natural gas from its existing Robards Junction facilities in Henderson County, Kentucky to one of Texas Gas' customers in Posey County, Indiana.

The EA assesses the potential environmental effects of the construction and operation of the Southern Indiana Market Lateral Project in accordance with the requirements of the National Environmental Policy Act (NEPA). The FERC staff concludes that approval of the proposed project, with appropriate mitigating measures, would not constitute a major federal action significantly affecting the quality of the human environment.

The U.S. Army Corps of Engineers—Louisville District participated as a cooperating agency in the preparation of the EA. Cooperating agencies have jurisdiction by law or special expertise with respect to resources potentially affected by a proposal and participate in the NEPA analysis.

The proposed Southern Indiana Market Lateral Project includes the following facilities:

- About 30.6 miles of 10-inch-diameter natural gas pipeline lateral;
- one new meter and regulator station;

- one pig[1] launcher; and
- one mainline valve.

The FERC staff mailed copies of the EA to federal, state, and local government representatives and agencies; elected officials; environmental and public interest groups; Native American tribes; potentially affected landowners and other interested individuals and groups; newspapers and libraries in the project area; and parties to this proceeding. In addition, the EA is available for public viewing on the FERC's Web site (*www.ferc.gov*) using the eLibrary link. A limited number of copies of the EA are available for distribution and public inspection at: Federal Energy Regulatory Commission, Public Reference Room, 888 First Street NE., Room 2A, Washington, DC 20426, (202) 502–8371.

Any person wishing to comment on the EA may do so. Your comments should focus on the potential environmental effects, reasonable alternatives, and measures to avoid or lessen environmental impacts. The more specific your comments, the more useful they will be. To ensure that the Commission has the opportunity to consider your comments prior to making its decision on this project, it is important that we receive your comments in Washington, DC on or before October 14, 2015.

For your convenience, there are three methods you can use to file your comments with the Commission. In all instances please reference the project docket number (CP15–14–001) with your submission. The Commission encourages electronic filing of comments and has expert staff available to assist you at (202) 502–8258 or *efiling@ferc.gov.*

(1) You can file your comments electronically using the eComment feature located on the Commission's Web site (*www.ferc.gov*) under the link to Documents and Filings. This is an easy method for submitting brief, text-only comments on a project;

(2) You can also file your comments electronically using the eFiling feature on the Commission's Web site (*www.ferc.gov*) under the link to Documents and Filings. With eFiling, you can provide comments in a variety of formats by attaching them as a file with your submission. New eFiling users must first create an account by clicking on ''eRegister.'' You must select the type of filing you are making. If you are filing a comment on a particular project, please select ''Comment on a Filing''; or

(3) You can file a paper copy of your comments by mailing them to the following address: Kimberly D. Bose, Secretary, Federal Energy Regulatory Commission, 888 First Street NE., Room 1A, Washington, DC 20426.

Any person seeking to become a party to the proceeding must file a motion to intervene pursuant to Rule 214 of the Commission's Rules of Practice and Procedures (18 CFR 385.214).[2] Only intervenors have the right to seek rehearing of the Commission's decision. The Commission grants affected landowners and others with environmental concerns intervenor status upon showing good cause by stating that they have a clear and direct interest in this proceeding which no other party can adequately represent. Simply filing environmental comments will not give you intervenor status, but you do not need intervenor status to have your comments considered.

Additional information about the project is available from the Commission's Office of External Affairs, at (866) 208–FERC, or on the FERC Web site (*www.ferc.gov*) using the eLibrary link. Click on the eLibrary link, click on ''General Search,'' and enter the docket number excluding the last three digits in the Docket Number field (*i.e.,* CP15–14). Be sure you have selected an appropriate date range. For assistance, please contact FERC Online Support at *FercOnlineSupport@ferc.gov* or toll free at (866) 208–3676, or for TTY, contact (202) 502–8659. The eLibrary link also provides access to the texts of formal documents issued by the Commission, such as orders, notices, and rulemakings.

In addition, the Commission offers a free service called eSubscription which allows you to keep track of all formal issuances and submittals in specific dockets. This can reduce the amount of time you spend researching proceedings by automatically providing you with notification of these filings, document summaries, and direct links to the documents. Go to *www.ferc.gov/docs-filing/esubscription.asp.*

Dated: September 14, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23425 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

[1] A ''pig'' is a tool that is inserted into and moves through the pipeline, and is used for cleaning the pipeline, internal inspections, or other purposes.

[2] See the previous discussion on the methods for filing comments.

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. EL15–2–000]

UIF GP, LLC; Notice of Supplement To Petition for Declaratory Order

Take notice that on September 11, 2015, UIF GP, LLC (UIF or Petitioner) submitted a supplement to its October 3, 2014 filed petition for declaratory order (petition) requesting that the Commission (1) disclaim jurisdiction over UIF, which acquired passive, non-managing Class A–1 ownership interests and passive, non-managing Class B ownership interests in Neptune Regional Transmission System, LLC (Neptune) as a public utility and (2) disclaim jurisdiction over future UIF transfers of the Class A–1 interests or Class B interests in Neptune, as more fully explained in the petition.

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 Petitioner.

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 5 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: 5:00 p.m. Eastern time on September 24, 2015.

Dated: September 14, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23422 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

[Docket No. CP15–548–000]

ANR Pipeline Company; Notice of Request Under Blanket Authorization

Take notice that on September 2, 2015, ANR Pipeline Company (ANR) 700 Louisiana Street, Suite 700, Houston, Texas 77002, filed in Docket No. CP15–548–000 a prior notice request pursuant to sections 157.205 and 157.216 of the Commission's regulations under the Natural Gas Act for authorization to abandon two compressor units and associated appurtenances at its Patterson Compressor Station (Patterson CS) located in Mary Parish, Louisiana, all as more fully set forth in the application which is on file with the Commission and open to public 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, please contact FERC Online Support at *FERCOnlineSupport@ferc.gov* or toll free at (866) 208–3676, or TTY, contact (202) 502–8659.

Any questions concerning this application may be directed to Linda Farquhar, Manager, Project Determinations & Regulatory Administration, ANR Pipeline Company, 700 Louisiana Street, Suite 700, Houston, Texas 77002–2700, at (832) 320–5685 or by email at *linda_farquhar@transcanada.com.*

Specifically, ANR proposes to abandon in place two Clark HRA–6 compressor units, rated at 1,000 horsepower (hp) each. ANR states that the subject compressor units have not been utilized to serve any ANR customer in the past year.

Pursuant to section 157.9 of the Commission's rules, 18 CFR 157.9, within 90 days of this Notice the Commission staff will either: Complete its environmental assessment (EA) and place it into the Commission's public record (eLibrary) for this proceeding; or issue a Notice of Schedule for Environmental Review. If a Notice of Schedule for Environmental Review is issued, it will indicate, among other milestones, the anticipated date for the Commission staff's issuance of the final environmental impact statement (FEIS) or EA for this proposal. The filing of the EA in the Commission's public record for this proceeding or the issuance of a Notice of Schedule for Environmental Review will serve to notify federal and state agencies of the timing for the completion of all necessary reviews, and the subsequent need to complete all federal authorizations within 90 days of the date of issuance of the Commission staff's FEIS or EA.

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 Natural Gas Act (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.

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.

Dated: September 11, 2015.

Kimberly D. Bose,

Secretary.

[FR Doc. 2015–23427 Filed 9–17–15; 8:45 am]

BILLING CODE 6717–01–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–ORD–2015–0635; FRL–9934–34–ORD]

Board of Scientific Counselors (BOSC) Chemical Safety for Sustainability Subcommittee Meeting; October 2015

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of meeting.

SUMMARY: Pursuant to the Federal Advisory Committee Act, Public Law 92–463, the U.S. Environmental Protection Agency, Office of Research and Development (ORD), gives notice of a meeting of the Board of Scientific Counselors (BOSC) Chemical Safety for Sustainability Subcommittee.

DATES: The meeting will be held on Tuesday, October 6, 2015, from 8:00 a.m. to 5:30 p.m., Wednesday, October 7, 2015, from 8:30 a.m. to 5:30 p.m., and will continue on Thursday, October 8, 2015, from 8:30 a.m. to 3:30 p.m. All times noted are Eastern Time. Attendees must register online by September 25, 2015. Requests for the draft agenda or for presenting written or oral statements at the meeting will be accepted up to October 2, 2015.

ADDRESSES: The meeting will be held at the EPA's Main Campus Facility, 109 T.W. Alexander Drive, Research Triangle Park, North Carolina 27711. Submit your comments, identified by Docket ID No. EPA–HQ–ORD–2015–0635, by one of the following methods:

• *www.regulations.gov:* Follow the on-line instructions for submitting comments.

• *Email:* Send comments by electronic mail (email) to: *ORD.Docket@epa.gov,* Attention Docket ID No. EPA–HQ–ORD–2015–0635.

• *Fax:* Fax comments to: (202) 566–0224, Attention Docket ID No. EPA–HQ–ORD–2015–0635.

• *Mail:* Send comments by mail to: Board of Scientific Counselors (BOSC) Chemical Safety for Sustainability Subcommittee Docket, Mail Code: 2822T, 1301 Constitution Ave. NW., Washington, DC, 20004, Attention Docket ID No. EPA–HQ–ORD–2015–0635.

• *Hand Delivery or Courier:* Deliver comments to: EPA Docket Center (EPA/DC), Room 3334, William Jefferson Clinton West Building, 1301 Constitution Ave. NW., Washington, DC, Attention Docket ID No. EPA–HQ–ORD–2015–0635. Note: this is not a mailing address. Deliveries are only accepted during the docket's normal hours of operation, and special arrangements should be made for deliveries of boxed information.

FOR FURTHER INFORMATION CONTACT: The Designated Federal Officer via mail at: Megan Fleming, Mail Code 8104R, Office of Science Policy, Office of Research and Development, U.S. Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; via phone/voice mail at: (202) 564–6604; or via email at: *fleming.megan@epa.gov.*

SUPPLEMENTARY INFORMATION:

General Information: The meeting is open to the public. Any member of the public interested in attending the meeting must register by September 25, 2015, online at: *https://www.eventbrite.com/e/us-epa-bosc-*

chemical-safety-for-sustainability-subcommittee-tickets-17480477579. Any member of the public interested in receiving a draft agenda, attending the meeting, or presenting written or oral statements at the meeting should contact Megan Fleming, the Designated Federal Officer, via any of the contact methods listed in the **FOR FURTHER INFORMATION CONTACT** section above.

For security purposes, all attendees must go through a metal detector, sign in with the security desk, and show government-issued photo identification to enter the building. Attendees are encouraged to arrive at least 15 minutes prior to the start of the meeting to allow sufficient time for security screening. Proposed agenda items for the meeting include, but are not limited to, the following: Overview of materials provided to the subcommittee; Overview of ORD's Chemical Safety for Sustainability Research Program; Overview of a small portion of ORD's Human Health Risk Assessment Research Program; Poster session; and Subcommittee discussion.

Instructions: Direct your comments to Docket ID No. EPA–HQ–ORD–2015–0635. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *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 the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, any form of encryption, and be free of any defects or viruses. For additional information about the EPA's public docket visit the EPA Docket Center homepage at *http://www.epa.gov/dockets/.*

Docket: All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the Board of Scientific Counselors (BOSC) Chemical Safety for Sustainability Subcommittee Docket, EPA/DC, William Jefferson Clinton West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the ORD Docket is (202) 566–1752.

Written Statements: Written statements for the public meeting should be received by Megan Fleming, DFO, via email at the contact information listed above by October 2, 2015. Written statements should be supplied in one of the following electronic formats: Adobe Acrobat PDF, MS Word, MS Power Point, or Rich Text format.

Oral Statements: In general, each individual making an oral statement at the public meeting will be limited to a total of three minutes. Each person making an oral statement should also consider providing written comments so that the points presented orally can be expanded upon in writing. Interested parties should contact Megan Fleming, DFO, in writing (preferably via email) at the contact information noted above by October 2, 2015, to be placed on the list of public speakers for the BOSC meeting.

Information on Services for Individuals with Disabilities: For information on access or services for individuals with disabilities, please contact Megan Fleming at (202) 564–6604 or *fleming.megan@epa.gov.* To request accommodation of a disability, please contact Megan Fleming, preferably at least ten days prior to the meeting, to give the EPA as much time as possible to process your request.

Dated: September 8, 2015.

Fred S. Hauchman,

Director, Office of Science Policy.

[FR Doc. 2015–23478 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OPP–2015–0452; FRL–9933–46]

Product Cancellation Order for Certain Pesticide Registrations

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: This notice announces EPA's order for the cancellations, voluntarily requested by the registrants and accepted by the Agency, of the products listed in Table 1 of Unit II., pursuant to the Federal Insecticide, Fungicide, and Rodenticide Act (FIFRA). This cancellation order follows a July 28, 2015 **Federal Register** Notice of Receipt of Requests from the registrants listed in Table 2 of Unit II. to voluntarily cancel these product registrations. In the July 28, 2015 notice, EPA indicated that it would issue an order implementing the cancellations, unless the Agency received substantive comments within the 30-day comment period that would merit its further review of these requests, or unless the registrants withdrew their requests. The Agency did not receive any comments on the notice. Further, the registrants did not withdraw their requests. Accordingly, EPA hereby issues in this notice a cancellation order granting the requested cancellations. Any distribution, sale, or use of the products subject to this cancellation order is permitted only in accordance with the terms of this order, including any existing stocks provisions.

DATES: The cancellations are effective September 18, 2015.

FOR FURTHER INFORMATION CONTACT: Donna Kamarei, Antimicrobials Division (7510P), Office of Pesticide Programs, Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460–0001; telephone number: (703) 347–0443; email address: *kamarei.donna@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this action apply to me?

This action is directed to the public in general, and may be of interest to a wide range of stakeholders including environmental, human health, and agricultural advocates; the chemical industry; pesticide users; and members of the public interested in the sale, distribution, or use of pesticides. Since others also may be interested, the Agency has not attempted to describe all the specific entities that may be affected by this action.

B. How can I get copies of this document and other related information?

The docket for this action, identified by docket identification (ID) number EPA–HQ–OPP–2015–0452, is available at *http://www.regulations.gov* or at the Office of Pesticide Programs Regulatory Public Docket (OPP Docket) in the Environmental Protection Agency Docket Center (EPA/DC), West William Jefferson Clinton Bldg., Rm. 3334, 1301 Constitution Ave. NW., Washington, DC 20460–0001. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the OPP Docket is (703) 305–5805. Please review the visitor instructions and additional information about the docket available at *http://www.epa.gov/dockets.*

II. What action is the agency taking?

This notice announces the cancellation, as requested by registrants, of products registered under FIFRA section 3 (7 U.S.C. 136a). These registrations are listed in sequence by registration number in Table 1 of this unit.

TABLE 1—PRODUCT CANCELLATIONS

EPA Registration No.	Product name	Chemical name
000499–00368	Whitmire PT 2000 Green-Shield Horticultural Algicide, Disinfectant.	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
000499–00482	TC 192	1-Decanaminium, N-decyl-N,N-dimethyl-, chloride.
000499–00542	TC–287	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
000875–00109	Quat-256	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
000875–00187	D-Trol, Disinfectant, Sanitizer & Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001007–00098	Quat-A-Mone	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001203–00041	Delta Foremost 3066 ES Show-off Germicidal Concentrate	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001258–01269	Baquacil Premium Algaecide	Poly(oxy-1,2-ethanediyl(dimethylimino)-1,2-ethanediyl(dimethylimino)-1,2-ethanediyl dichloride).
001258–01335	Vantocil NR 3.8	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
001270–00184	Zep Lemonex Germicidal Detergent	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001270–00191	Zep Venture	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001270–00235	Zep Bowl Shine	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001677–00232	Lonza SQ Sanitizer/Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
001706–00177	Nalcon 7642	Dialkyl * methyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5% C12), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
001839–00101	CD 1.6 (D & F) Detergent/Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001839–00103	CD 3.2 (D & F) Detergent/Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
001839–00146	NP 1.8 D&F Detergent/Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
001839–00160	BTC 885 Thickened Phosphoric Acid Germicidal Bowl Cleaner.	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
002212–00016	Elimstaph No. 2	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
002296–00097	Bacti-Chem General Type Detergent Cleaner-Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
002296–00107	Lemon-Quat Disinfectant Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
002296–00108	Pine Quat	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
002296–00109	Cherry-Quat	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).

TABLE 1—PRODUCT CANCELLATIONS—Continued

EPA Registration No.	Product name	Chemical name
002724–00517	Speer Germicidal Multi-Purpose Cleaner	Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14), Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
002724–00518	Magic Guard Disinfectant/Sanitizer/Deodorizer	Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14), Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
002724–00519	Magic Guard Cleaner/Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
002724–00562	Magic Guard Lemon Odor Disinfectant-Deodorant-Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
002935–00548	Hyamine Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
003635–00278	X-Cell 420	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Dialkyl * methyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
003862–00075	Mint 7	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
003862–00185	Spur-Tex Disinfectant Cleaner-Deodorant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
004822–00370	S.C. Johnson Wax Toilet Duck	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
004822–00484	BD1	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
004822–00546	Dexter 1	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
004822–00577	Rut Disinfectant Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
005813–00031	Pine Sol Household Cleaner Disinfectant	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride.
005813–00034	Pine-Sol Multi-purpose Cleaner Disinfectant	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride.
005813–00035	Pine-Sol Presto	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride.
005813–00059	Clorox Disinfecting Spray III	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
005813–00067	Clorox 409–R	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride, Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
005813–00074	Clorox TLC	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride, Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
005813–00088	Julia	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
005813–00097	Brac	1-Octanaminium, N,N-dimethyl-N-octyl-, chloride, and Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00001	Barquat LB–50	Alkyl * dimethyl benzyl ammonium chloride * (65%C12, 25%C14, 10%C16).
006836–00011	Barquat OJ–50	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
006836–00031	Lonza Sanitizer-Cleaner 45–7	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00033	Lonza Formulation 70–12	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00035	Barquat MX–80	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00036	Barquat MX–50	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00047	Barquat OJ–10 Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
006836–00055	Barquat MB 80–10	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00056	Barquat 42–10	Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).

TABLE 1—PRODUCT CANCELLATIONS—Continued

EPA Registration No.	Product name	Chemical name
006836–00069	Lonza Barquat MX 80–10	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00076	Lonza Formulation S–23	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00079	205M Water Treatment Microbiocide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00080	Bardac 203–MP	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00082	Barquat OJ–80	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
006836–00096	Hyamine 10–X (Crystals)	Benzenemethanaminium, N,N-dimethyl-N-(2-(2-(methyl-4-(1,1,3,3-tetramethylbutyl)phenoxy)ethoxy)ethyl)-, chloride.
006836–00097	Benzethonium Chloride USP Germicide Concentrate	Benzenemethanaminium, N,N-dimethyl-N-(2-(2-(4-(1,1,3,3-tetramethylbutyl)phenoxy)ethoxy)ethyl)-, chloride.
006836–00106	Hyamine 3500 W/E–80%	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00155	Bio-Quat 50–24	Alkyl * dimethyl benzyl ammonium chloride * (61%C12, 23%C14, 11%C16, 2.5%C18 2.5%C10 and trace of C8).
006836–00160	Bio Quat 50–35	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
006836–00161	Bio-Quat 80–24 for Manufacturing use only	Alkyl * dimethyl benzyl ammonium chloride * (61%C12, 23%C14, 11%C16, 2.5%C18 2.5%C10 and trace of C8).
006836–00166	Bio-Guard M–15 Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
006836–00170	Bio Quat T–501	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00171	Bio-Quat 80–28R	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
006836–00172	Bio-Quat 50–36	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00173	Bio Quat 50–28R	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
006836–00174	Bio Quat 80–36	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
006836–00175	Bio-Quat 80–35	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
006836–00183	Bio-Quat 50–60, Disinfectant, Fungicide, Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00186	Barquat 80–28RX	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00187	Bio Quat 80–42	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00188	Bio Quat 50–42	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00189	Bio Quat 50–30	Alkyl * dimethyl benzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
006836–00190	Bio Quat 50–25	Alkyl * dimethyl benzyl ammonium chloride * (67%C12, 25%C14, 7%C16, 1%C8, C10, and C18).
006836–00191	Barquat 50–65	Decyl isononyl dimethyl ammonium chloride.
006836–00209	Bardac 2180	Decyl isononyl dimethyl ammonium chloride.
006836–00218	Bardac RW–10	Decyl isononyl dimethyl ammonium chloride.
006836–00219	Bardac CW–10	Decyl isononyl dimethyl ammonium chloride.
006836–00220	Bardac CW–50	Decyl isononyl dimethyl ammonium chloride.
006836–00221	Bardac RW–50	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00227	Lonza Formulation DC–800	Decyl isononyl dimethyl ammonium chloride.
006836–00228	Bardac 2150 LA	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00230	Jordaquat 350	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
006836–00244	CSP–46 Concentrate	Alkyl * dimethyl benzyl ammonium chloride * (67%C12, 25%C14, 7%C16, 1%C18).
006836–00285	BarquaT 50–65A	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).

TABLE 1—PRODUCT CANCELLATIONS—Continued

EPA Registration No.	Product name	Chemical name
006836–00294	Bardac 255M	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00295	Bardac 288M	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00298	Barquat MB–40 Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00301	Lonza Formulation FC–600	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
006836–00320	Lonza CQ Disinfectant Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
006943–00001	Kork Rub Cleaner Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
007364–00090	Pool-Pal 500 Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
008540–00003	Formula No. 30–A	1-Decanaminium, N-decyl-N,N-dimethyl-, chloride.
008540–00013	Garratt Callahan Formula 35	Benzenemethanaminium, N,N-dimethyl-N-(2-(2-(4-(1,1,3,3-tetramethylbutyl)phenoxy)ethoxy)ethyl)-, chloride.
008660–00061	Vertagreen Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (67%C12, 25%C14, 7%C16, 1%C18), and Dialkyl * methyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
008959–00036	Portatrine	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
009367–00005	Emulso Germicidal Bowl Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
009367–00045	Mint-O	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
009386–00014	AMA–3510	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
009688–00056	Deodorizing Disinfecting Cleaner I	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
009688–00057	Chemsico Spray Disinfectant I with Bacteriostatic Action	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
009688–00135	Chemsico Surface Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (61%C12, 23%C14, 11%C16, 5%C18).
010324–00002	Maquat LC12S–80%	Alkyl * dimethyl benzyl ammonium chloride * (95%C14, 3%C12, 2%C16).
010324–00121	Maquat 2855	Alkyl * dimethyl benzyl ammonium chloride * (95%C14, 3%C12, 2%C16).
010324–00135	Maquat MC1412–55%	Alkyl * dimethyl benzyl ammonium chloride * (65%C12, 25%C14, 10%C16).
010707–00008	Magnacide 408 Industrial Bactericide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
012204–00010	Marcicide	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
037265–00042	Pine Odor Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
037265–00049	Strike Bac Lemon Odor Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
045309–00017	Aquaclear Algaecide Formula-5	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
045309–00032	Free ’N Clear Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Dialkyl * methyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
045309–00033	Free N’ Clear 10 Swimming Pool Algaecide	1-Decanaminium, N-decyl-N,N-dimethyl-, chloride.
045309–00044	Swim Free Concentrated Poly-Cide II Algaecide for Swimming Pools.	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047000–00087	Super sweet Multi-Purpose Disinfectant	Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).

TABLE 1—PRODUCT CANCELLATIONS—Continued

EPA Registration No.	Product name	Chemical name
047371–00001	Formulation HS–32Q	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00006	Formulation HS–652Q	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00010	FMB 451–8 Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00011	FMB 451–5 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
047371–00013	FMB 6075–8 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
047371–00014	FMB 3328–8 Quat	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18).
047371–00015	FMB 6075–5 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
047371–00016	FMB 4500–5 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00018	FMB 451–28 Quat Concentrated Germicide	Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
047371–00019	FMB 3328–5 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
047371–00020	FMB 3328–28 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
047371–00022	FMB 4500–28 Quat	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00032	Formulation HS–8451P	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
047371–00035	Formulation HS–33A	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00046	SAK–64L Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047371–00050	Huntington FMB 65–15 Quat	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047371–00051	Lonza FMB–28 Quat	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00055	WTM–1210 Water Treatment Microbiocide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00061	FMB 1210–100 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
047371–00062	FMB 28–28 Quat	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
047371–00063	FMB 3328–D40 Quat Concentrated Germicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047371–00069	HS–65 Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00070	Huntington FMB 504–5 Quat	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00073	FMB 504–8 Quat	Alkyl * dimethyl benzyl ammonium chloride * (58%C14, 28%C16, 14%C12).
047371–00085	FMB 28–15 Quat Concentrated Germicide	Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
047371–00089	Formulation AE–90	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047371–00092	HS–65 Winterizing Algicide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00101	Formulation PA–1210	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00102	Formulation POQ 1210	Alkyl * dimethyl ethylbenzyl ammonium chloride * (50%C12, 30%C14, 17%C16, 3%C18), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).

TABLE 1—PRODUCT CANCELLATIONS—Continued

EPA Registration No.	Product name	Chemical name
047371–00104	Formulation HS–3328	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00105	Formulation POQ–451	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
047371–00107	Formulation HS–65 Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00149	PA–1210 Humidifier Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00153	Formulation POQ451 (1:32)	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00161	HS–451 Disinfectant/Sanitizer (50%)	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
047371–00181	WTM–1210 Microbicide (33%)	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
048181–00001	Hydrocide Germicide and Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
061282–00060	Tryad	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
063664–00001	QSP–451 Swimming Pool Algaecide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 25%C12, 15%C16).
067262–00015	Aqua Chem Balanced for Clean Pools Algaecide Liquid	Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14), and Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
067517–00017	Quaternary Disinfectant	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
067517–00019	Odor Control	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
067517–00039	Annihilator Cleaner/Disinfectant	1-Decanaminium, N,N-dimethyl-N-octyl-, chloride, and Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
067619–00003	CPPC Spray 1	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
067619–00005	CPPC PS Spray 19054	1-Decanaminium, N,N-dimethyl-N-octyl-, chloride, and Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
067619–00022	LEX	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
070627–00001	Spray Disinfectant HG	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
070627–00059	Antibacterial Scrubbing Bubbles Bathroom Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
070627–00064	Butcher's Bright Disinfectant Foam Cleaner	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
070627–00065	Butcher's Clockwork Disinfectant Deodorizer Sanitizer	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
070627–00066	Butcher's Bath Guard Acid Free Disinfectant Bathroom Cleaner.	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
074655–00003	Spectrum RX–36	Alkyl * dimethyl benzyl ammonium chloride * (50%C14, 40%C12, 10%C16).
074655–00015	Spectrum RX1000	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12).
081002–00001	Chlorine Free Splashes Algicide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).
090924–00008	Bactron K–86 Microbiocide	Alkyl * dimethyl benzyl ammonium chloride * (60%C14, 30%C16, 5%C18, 5%C12), and Alkyl * dimethyl ethylbenzyl ammonium chloride * (68%C12, 32%C14).

Table 2 of this unit includes the names and addresses of record for all registrants of the products in Table 1 of this unit, in sequence by EPA company number. This number corresponds to the first part of the EPA registration numbers of the products listed in Table 1 of this unit.

TABLE 2—REGISTRANTS OF CANCELLED PRODUCTS

EPA company No.	Company name and address
499	BASF Corporation, 26 Davis Drive, Research Triangle Park, NC 27709.
875	Diversey, Inc., 8310 16th Street, Sturtevant, WI 53177.
1007	Zoetis, Inc., 333 Portage Street, Kalamazoo, MI 49007–4931.
1203	Delta Foremost Chemical Corp., 3915 Air Park Street, Memphis, TN 38118.
1258	Arch Chemicals, Inc., 1200 Bluegrass Lakes Parkway, Alpharetta, GA 30004.
1270	Zep, Inc., 1259 Seaboard Industrial Blvd. NW., Atlanta, GA 30318.
1677	Ecolab, Inc., 370 Wabasha Street North, St. Paul, MN 55102.
1706	Nalco Company, 370 N. Wabasha Street, St. Paul, MN 55102–1390.
1839	Stepan Company, 22 W. Frontage Rd., Northfield Rd., IL 60093.
2212	Walter G. Legge Company, Inc., 444 Central Avenue, Peekskill, NY 10566.
2296	National Chemical Laboratories, Inc., 401 N. 10th Street, Philadelphia, PA 19123.
2724	Wellmark International, 1501 E. Woodfield Road, Suite 200 West, Schaumburg, IL 60173.
2935	Wilbur-Ellis Company, 2903 S. Cedar Avenue, Fresno, CA 93725.
3635	Dubois Chemicals, Inc., 3630 E. Kemper Road, Cincinnati, OH 45241.
3862	ABC Compounding Co., Inc., P.O. Box 16247, Atlanta, GA 30321–0247.
4822	S.C. Johnson & Son, Inc., 1525 Howe Street, Racine, WI 53403.
5813	The Clorox Co., C/O PS&RC, P.O. Box 493, Pleasanton, CA 94566–0803.
6836	Lonza, Inc., 90 Boroline Road, Allendale, NJ 07401.
6943	Tate Soaps & Surfactants, Inc., P.O. Box 2543, Kokomo, IN 46904–2543.
7364	GLB Pool & Spa, 90 Boroline Road, Allendale, NJ 07401.
8540	Garratt-Callahan Co., 50-Ingold Road, Burlingame, CA 94010.
8660	United Industries Corp., P.O. Box 142642, St. Louis, MO 63114–0642.
8959	Applied Biochemists, 90 Boroline Road, Allendale, NJ 07401.
9367	Theo Chem Laboratories, Inc., 7373 Rowlett Park Drive, Tampa, FL 33610–1141.
9386	Kemira Chemicals, Inc., 1000 Parkwood Circle, Suite 500, Atlanta, GA 30339.
9688	Chemsico, One Rider Trail Plaza Drive, Suite 300, Earth City, MO 63045, Lithia Springs, GA 30122.
10324	Mason Chemical Company, 723 W. Algonquin Rd., Suite B, Arlington Heights, IL 60005.
10707	Baker Petrolite, LLC., 12645 West Airport Blvd., Sugar Land, TX 77478.
12204	Mid-American Research Chemical Corp., P.O. Box 927, Columbus, NE 68602–0927.
37265	Genlabs, 5568 Schaefer Avenue, Chino, CA 91710.
45309	Aqua Clear Industries, LLC., P.O. Box 2456, Suwanee, GA 30024–0980.
47000	Chem-tech, LTD., 4515 Fleur Drive #303, Des Moines, IA 50321.
47371	H & S Chemicals Division, 90 Boroline Road, Allendale, NJ 07401.
48181	Hydrox Laboratories, 825 Tollgate Rd., Elgin, IL 60123.
63664	Quality Swimming Pool Products Division, 90 Boroline Road, Allendale, NJ 07401.
67262	Recreational Water Products, Inc., P.O. Box 1449, Buford, GA 30515–1449.
67517	PM Resources, Inc., 3200 Meacham Boulevard, Fort Worth, TX 76137.
67619	Clorox Professional Products Co. C/O PS&RC, P.O. Box 493, Pleasanton, CA 94566–0803.
70627	Diversey, Inc., 8310 16th Street, Sturtevant, WI 53177.
74655	Solenis, LLC., 7910 Baymeadows Way, Suite 100, Jacksonville, FL 32256.
81002	Splashes, Inc., 90 Boroline Road, Allendale, NJ 07401.
90924	Nalco Champion, 370 Wabasha Street North, St. Paul, MN 55102–1390.

III. Summary of Public Comments Received and Agency Response to Comments

During the public comment period provided, EPA received no comments in response to the July 28, 2015 **Federal Register** notice announcing the Agency's receipt of the requests for voluntary cancellations of products listed in Table 1 of Unit II.

IV. Cancellation Order

Pursuant to FIFRA section 6(f) (7 U.S.C. 136d(f)), EPA hereby approves the requested cancellations of the registrations identified in Table 1 of Unit II. Accordingly, the Agency hereby orders that the product registrations identified in Table 1 of Unit II. are canceled. The effective date of the cancellations that are the subject of this notice is September 18, 2015. Any distribution, sale, or use of existing stocks of the products identified in Table 1 of Unit II. in a manner inconsistent with any of the provisions for disposition of existing stocks set forth in Unit VI. will be a violation of FIFRA.

V. What is the Agency's authority for taking this action?

Section 6(f)(1) of FIFRA (7 U.S.C. 136d(f)(1)) provides that a registrant of a pesticide product may at any time request that any of its pesticide registrations be canceled or amended to terminate one or more uses. FIFRA further provides that, before acting on the request, EPA must publish a notice of receipt of any such request in the **Federal Register**. Thereafter, following the public comment period, the EPA Administrator may approve such a request. The notice of receipt for this action was published for comment in the **Federal Register** of July 28, 2015 [(80 FR 44953) (FRL–9930–15)]. The comment period closed on August 27, 2015.

VI. Provisions for Disposition of Existing Stocks

Existing stocks are those stocks of registered pesticide products which are currently in the United States and which were packaged, labeled, and released for shipment prior to the effective date of the cancellation action. The existing stocks provisions for the products subject to this order are as follows.

B. For Products 10324–00002, 10324–00121, and 10324–00135

The registrant has requested to the Agency via letter to sell existing stocks for an 18-month period for products 10324–00002, 10324–00121, and 10324–00135. Because the Agency has identified no significant potential risk concerns associated with these pesticide products, upon cancellation of products 10324–00002, 10324–00121, and 10324–00135, EPA anticipates allowing the registrant to sell and distribute existing stocks of these products until March 20, 2017. Thereafter, the registrant is prohibited from selling or distributing these products listed in Table 1, except for export in accordance with FIFRA section 17 (7 U.S.C. 136o), or proper disposal. Persons other than the registrants may sell, distribute, or use existing stocks of products 10324–00002, 10324–00121, and 10324–00135 until existing stocks are exhausted, provided that such sale, distribution, or use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled products.

B. For All Other Products Identified in Table 1 of Unit II

The registrants may continue to sell and distribute existing stocks of all other products listed in Table 1 of Unit II. until September 19, 2016, which is 1-year after the publication of the Cancellation Order in the **Federal Register**. Thereafter, the registrants are prohibited from selling or distributing all other products listed in Table 1, except for export in accordance with FIFRA section 17 (7 U.S.C. 136o), or proper disposal. Persons other than the registrants may sell, distribute, or use existing stocks of all other products listed in Table 1 of Unit II. until existing stocks are exhausted, provided that such sale, distribution, or use is consistent with the terms of the previously approved labeling on, or that accompanied, the canceled products.

Authority: 7 U.S.C. 136 *et seq.*

Dated: September 9, 2015.

Steve Knizner,

Director, Antimicrobials Division, Office of Pesticide Programs.

[FR Doc. 2015–23473 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OW–2004–0013; FRL–9934–37–OW]

Proposed Information Collection Request; Comment Request; EPA Strategic Plan Information on Source Water Protection

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is planning to submit an information collection request (ICR), ''EPA Strategic Plan Information on Source Water Protection'' (EPA ICR No. 1816.06, OMB Control No. 2040–0197) to the Office of Management and Budget (OMB) for review and approval in accordance with the Paperwork Reduction Act (PRA) (44 U.S.C. 3501 *et seq.*). Before doing so, EPA is soliciting public comments on specific aspects of the proposed information collection as described in this renewal notice. This is a proposed extension of the existing ICR, which is approved through December 31, 2015. 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.

DATES: Comments must be submitted on or before November 17, 2015.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OW–2004–0013, on-line using *www.regulations.gov* (our preferred method), by email to the OW Docket at *OW-Docket@epa.gov or by mail to the* Water Docket, Environmental Protection Agency, EPA Docket Center (EPA/DC), Mail Code: 28221T, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

EPA's policy is that all comments received will be included in the public docket without change including any personal information provided, unless the comment includes profanities, threats, information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute.

FOR FURTHER INFORMATION CONTACT: Beth Hall, Drinking Water Protection Division—Prevention Branch, Office of Ground Water and Drinking Water (MC 4606M), Environmental Protection Agency, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: 202–564–3883; fax number: 202–564–3756; email address: *hall.beth@epa.gov.*

SUPPLEMENTARY INFORMATION: Supporting documents that explain in detail the information that EPA will be collecting are available in the public docket for this ICR. The docket can be viewed online at *http://www.regulations.gov* or in person at the EPA Docket Center, WJC West, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The telephone number for the Docket Center is 202–566–1744. For additional information about EPA's public docket, visit *http://www.epa.gov/dockets.*

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. 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. At that time, EPA will issue another **Federal Register** notice to announce the submission of the ICR to OMB and the opportunity to submit additional comments to OMB.

Abstract: EPA is collecting, on a voluntary basis, data from the states on their progress toward substantial implementation of protection strategies for all community water systems (CWSs). The information to be collected will help states and EPA understand the progress toward the Agency's goal of increasing the number of CWSs (and the populations they serve) with minimized risk to public health through development and implementation of source water protection strategies for source water areas. In April of 2015, the National Water Program published guidance for meeting the water-related goals in the FY 2014–2018 EPA Strategic Plan. In keeping with this guidance, EPA specifically tracks the percentage of all CWSs that are implementing source water protection and the percentage of the total population which is served by those systems.

Form Numbers: None.

Respondents/affected entities: 51.

Respondent's obligation to respond: Voluntary.

Frequency of response: Annual.

Total estimated burden: 342 hours. Burden is defined at 5 CFR 1320.03(b).

T*otal estimated cost:* $14,853 (per year).

Changes in Estimates: There is a decrease in the total estimated burden of 1,026 hours and a decrease in the total estimated cost of $130,416 from the existing ICR. This decrease is because source water protection programs are maturing. State databases are fully developed and tracking is routine compared to the burden and costs calculated for the existing ICR. The change in costs due to increased hourly labor charges is also factored into this estimate.

Dated: September 14, 2015.

Peter Grevatt,

Director, Office of Ground Water and Drinking Water.

[FR Doc. 2015–23476 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[FRL–9934–24–Region 5]

Notification of a Public Teleconference of the Great Lakes Advisory Board

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice.

SUMMARY: The Environmental Protection Agency (EPA) announces a public teleconference of the Great Lakes Advisory Board (Board). The purpose of this teleconference is to discuss the Great Lakes Restoration Initiative (GLRI) covering FY15–19 and other relevant matters.

DATES: The teleconference will be held on Wednesday, October 7, 2015 from 9 a.m. to 11 a.m. Central Time, 10 a.m. to 12 p.m. Eastern Time. An opportunity will be provided to the public to comment.

ADDRESSES: The public teleconference will be held by teleconference only. The teleconference number is: (877) 744–6030; participant code: 31140236.

FOR FURTHER INFORMATION CONTACT: Any member of the public wishing further information regarding this teleconference may contact Rita Cestaric, Designated Federal Officer (DFO), by email at *cestaric.rita@epa.gov.* General information on the GLRI and the Board can be found at *http://glri.us/public.html.*

SUPPLEMENTARY INFORMATION:

Background: The Board is a federal advisory committee chartered under the Federal Advisory Committee Act (FACA), Public Law 92–463. EPA established the Board in 2013 to provide independent advice to the EPA Administrator in her capacity as Chair of the federal Great Lakes Interagency Task Force (IATF). The Board conducts business in accordance with FACA and related regulations.

The Board consists of 16 members appointed by EPA's Administrator in her capacity as IATF Chair. Members serve as representatives of state, local and tribal government, environmental groups, agriculture, business, transportation, educational institutions, and as technical experts.

Availability of teleconference materials: The agenda and other materials in support of the teleconference will be available at *http://glri.us/advisory/index.html.*

Procedures for providing public input: Federal advisory committees provide independent advice to federal agencies. Members of the public can submit relevant comments for consideration by the Board. Input from the public to the Board will have the most impact if it provides specific information for the Board to consider. Members of the public wishing to provide comments should contact the DFO directly.

Oral statements: In general, individuals or groups requesting an oral presentation at this public teleconference will be limited to three minutes per speaker, subject to the number of people wanting to comment. Interested parties should contact the DFO in writing (preferably via email) at the contact information noted above by October 5, 2015 to be placed on the list of public speakers for the teleconference.

Written statements: Written statements must be received by October 1, 2015 so that the information may be made available to the Board for consideration. Written statements should be supplied to the DFO in the following formats: One hard copy with original signature and one electronic copy via email. Commenters are requested to provide two versions of each document submitted: One each with and without signatures because only documents without signatures may be published on the GLRI Web page.

Accessibility: For information on access or services for individuals with disabilities, please contact the DFO at the phone number or email address noted above, preferably at least seven days prior to the teleconference, to give EPA as much time as possible to process your request.

Dated: September 9, 2015.

Cameron Davis,

Senior Advisor to the Administrator.

[FR Doc. 2015–23474 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

[ER–FRL–9022–9]

Environmental Impact Statements; Notice of Availability

Responsible Agency: Office of Federal Activities, General Information (202) 564–7146 or *http://www2.epa.gov/nepa.*

Weekly receipt of Environmental Impact Statements

Filed 09/07/2015 Through 09/11/2015

Pursuant to 40 CFR 1506.9.

Notice

Section 309(a) of the Clean Air Act requires that EPA make public its comments on EISs issued by other Federal agencies. EPA's comment letters on EISs are available at: *https://cdxnodengn.epa.gov/cdx-enepa-public/action/eis/search.*

EIS No. 20150259, Final, FRA, NC, Southeast High Speed Rail, Richmond, VA, to Raleigh, NC, Review Period Ends: 10/19/2015, Contact: John Winkle 202–493–6067.

EIS No. 20150260, Final, BR, CA, Central Valley Project Municipal and Industrial Water Shortage Policy, Review Period Ends: 10/19/2015, Contact: Timothy Rust 916–978–5516.

EIS No. 20150261, Final, DOE, HI, PROGRAMMATIC—Hawaii Clean Energy, Review Period Ends: 10/19/2015, Contact: Dr. Jane Summerson 800–472–2756.

EIS No. 20150262, Final, USFWS, VA, Chincoteague and Wallops Island National Wildlife Refuge Final CCP, Review Period Ends: 10/19/2015, Contact: Thomas Bonetti 413–253–8307.

EIS No. 20150263, Draft, BLM, USFS, ID, Draft Environmental Impact Statement Rasmussen Valley Mine, Comment Period Ends: 11/02/2015, Contact: Bill Volk 208–236–7503. The U.S. Department of the Interior's Bureau of Land Management and the U.S. Department of Agriculture's Forest Service are joint lead agencies for this project.

EIS No. 20150264, Final, FHWA, TN, Pellissippi Parkway Extension (State Route 162) from State Route 33 (Old Knoxville Highway) to US 321/State Route 73/Lamar Alexander Parkway, Review Period Ends: 10/19/2015, Contact: Theresa Claxton 615–781–5770.

Amended Notices

EIS No. 20150199, Draft, OSM, Other, Stream Protection Rule, Comment Period Ends: 10/26/2015, Contact: Robin Ferguson 202–208–2802

Revision to FR Notice Published 07/24/2015; Extending Comment Period from 09/15/2015 to 10/26/2015.

Dated: September 15, 2015.

Dawn Roberts,

Management Analyst, NEPA Compliance Division, Office of Federal Activities.

[FR Doc. 2015–23490 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

FEDERAL RESERVE SYSTEM

Formations of, Acquisitions by, and Mergers of Savings and Loan Holding Companies

The companies listed in this notice have applied to the Board for approval, pursuant to the Home Owners' Loan Act (12 U.S.C. 1461 *et seq.*) (HOLA), Regulation LL (12 CFR part 238), and Regulation MM (12 CFR part 239), and all other applicable statutes and regulations to become a savings and loan holding company and/or to acquire the assets or the ownership of, control of, or the power to vote shares of a savings association and nonbanking companies owned by the savings and loan 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 HOLA (12 U.S.C. 1467a(e)). 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 10(c)(4)(B) of the HOLA (12 U.S.C. 1467a(c)(4)(B)). 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 October 15, 2015.

A. Federal Reserve Bank of Boston (Prabal Chakrabarti, Senior Vice President) 600 Atlantic Avenue, Boston, Massachusetts 02210–2204:

1. *PB Bancorp, Inc.*, Putnam, Connecticut, to acquire 100 percent of the outstanding capital stock of Putnam Bank, Putnam, Connecticut, pursuant to regulations 12 CFR 239.55 and 238.11, in connection with the second-step conversion of Putnam Bancorp, MHC from mutual to stock form and the merger of PB Bancorp, Inc., with and into a merged entity of Putnam Bancorp, MHC and PSB Holdings, Inc., with PB Bancorp, Inc. as the survivor.

B. Federal Reserve Bank of St. Louis (Yvonne Sparks, Community Development Officer) P.O. Box 442, St. Louis, Missouri 63166–2034:

1. *Central Federal Bancshares, Inc.*, Rolla, Missouri; to become a savings and loan holding company by acquiring 100 percent of the voting shares of Central Savings and Loan Association of Rolla, Rolla, Missouri.

Board of Governors of the Federal Reserve System, September 15, 2015.

Michael J. Lewandowski,

Associate Secretary of the Board.

[FR Doc. 2015–23435 Filed 9–17–15; 8:45 am]

BILLING CODE 6210–01–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 October 15, 2015.

A. Federal Reserve Bank of Atlanta (Chapelle Davis, Assistant Vice President) 1000 Peachtree Street NE., Atlanta, Georgia 30309:

1. *Anthony T. Moore, Allison T. Moore, both of Burns, Tennessee, and Southeastern Bancorp, Inc.*, Dickson, Tennessee, to retain voting shares of Cumberland Bancorp, Inc., and thereby indirectly retain voting shares of Cumberland Bank & Trust, both in Clarksville, Tennessee.

B. Federal Reserve Bank of Dallas (Robert L. Triplett III, Senior Vice President) 2200 North Pearl Street, Dallas, Texas 75201–2272:

1. *Thomas George Chase, Jr.*, Waco, Texas; to acquire voting shares of CentraBanc Corporation, and thereby indirectly acquire voting shares of Central National Bank, both in Waco, Texas.

Board of Governors of the Federal Reserve System, September 15, 2015.

Michael J. Lewandowski,

Associate Secretary of the Board.

[FR Doc. 2015–23434 Filed 9–17–15; 8:45 am]

BILLING CODE 6210–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier CMS–2552–10]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

ACTION: Notice.

SUMMARY: The Centers for Medicare & Medicaid Services (CMS) is announcing an opportunity for the public to comment on CMS' intention to collect information from the public. Under the Paperwork Reduction Act of 1995 (PRA), federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, and to allow a second opportunity for public comment on the notice. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

DATES: Comments on the collection(s) of information must be received by the OMB desk officer by *October 19, 2015.*

ADDRESSES: When commenting on the proposed information collections, please reference the document identifier or OMB control number. To be assured consideration, comments and recommendations must be received by the OMB desk officer via one of the following transmissions: OMB, Office of Information and Regulatory Affairs, Attention: CMS Desk Officer, Fax Number: (202) 395–5806 *OR* Email: *OIRA_submission@omb.eop.gov.*

To obtain copies of a supporting statement and any related forms for the proposed collection(s) summarized in this notice, you may make your request using one of following:

1. Access CMS' Web site address at *http://www.cms.hhs.gov/PaperworkReductionActof1995.*
2. Email your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov.*
3. Call the Reports Clearance Office at (410) 786–1326.

FOR FURTHER INFORMATION CONTACT: Reports Clearance Office at (410) 786–1326.

SUPPLEMENTARY INFORMATION: Under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3520), federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. The term ''collection of information'' is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C. 3506(c)(2)(A)) requires federal agencies to publish a 30-day notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, before submitting the collection to OMB for approval. To comply with this requirement, CMS is publishing this notice that summarizes the following proposed collection(s) of information for public comment:

1. *Type of Information Collection Request:* Revision of a currently approved collection; *Title of Information Collection:* Hospital and Hospital Health Care Complex Cost Report; *Use:* Providers of services participating in the Medicare program are required under sections 1815(a) and 1861(v)(1)(A) of the Social Security Act (42 U.S.C. 1395g) to submit annual information to achieve settlement of costs for health care services rendered to Medicare beneficiaries. In addition, regulations at 42 CFR 413.20 and 413.24 require adequate cost data and cost reports from providers on an annual basis.

We are requesting the Office of Management and Budget review and approve this revision to the Form CMS–2552–10, Hospital and Hospital Health Care Complex Cost Report. These cost reports are filed annually by hospitals participating in the Medicare program to determine the reasonable costs incurred to provide medical services to patients. The revisions made to the hospital cost report are in accordance with the statutory requirement for hospice payment reform in § 3132 of the Patient Protection and Affordable Care Act (ACA) (March 23, 2010) and the statutory requirement establishing a prospective payment system for Federally Qualified Health Centers in § 10501(i)(3)(A) of the ACA, codified in section 1834(o) of the Act. *Form Number:* CMS–2552–10 (OMB control number 0938–0050); *Frequency:* Yearly; *Affected Public:* State, Local, or Tribal Governments, Private sector (For-profit and Not-for-profit institutions); *Number of Respondents:* 6,157; *Total Annual Responses:* 6,157; *Total Annual Hours:* 4,143,661. (For policy questions regarding this collection contact Gail Duncan at 410–786–7278).

Dated: September 15, 2015.

William N. Parham, III,

Director, Paperwork Reduction Staff, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2015–23462 Filed 9–17–15; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Centers for Medicare & Medicaid Services

[Document Identifier: CMS–10261]

Agency Information Collection Activities: Submission for OMB Review; Comment Request

ACTION: Notice and withdrawal of previous notice.

SUMMARY: The Centers for Medicare & Medicaid Services (CMS) is announcing an opportunity for the public to comment on CMS' intention to collect information from the public. Under the Paperwork Reduction Act of 1995 (PRA), federal agencies are required to publish notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, and to allow a second opportunity for public comment on the notice. Interested persons are invited to send comments regarding the burden estimate or any other aspect of this collection of information, including any of the following subjects: (1) The necessity and utility of the proposed information collection for the proper performance of the agency's functions; (2) the accuracy of the estimated burden; (3) ways to enhance the quality, utility, and clarity of the information to be collected; and (4) the use of automated collection techniques or other forms of information technology to minimize the information collection burden.

DATES: Comments on the collection(s) of information must be received by the OMB desk officer by October 19, 2015.

As of September 18, 2015 and as described below under ''Partial Withdrawal of Previous Notice,'' the CMS–10261-related portion of the notice that published on August 24, 2015 (80 FR 51275) is withdrawn.

ADDRESSES: When commenting, please reference the document identifier or OMB control number. To be assured consideration, comments and recommendations must be submitted in any one of the following ways:

1. *Electronically.* You may send your comments electronically to *http://www.regulations.gov.* Follow the instructions for ''Comment or Submission'' or ''More Search Options'' to find the information collection document(s) that are accepting comments.
2. *By regular mail.* You may mail written comments to the following address: CMS, Office of Strategic Operations and Regulatory Affairs, Division of Regulations Development, Attention: Document Identifier/OMB Control Number ________, Room C4–26–05, 7500 Security Boulevard, Baltimore, Maryland 21244–1850.

To obtain copies of a supporting statement and any related forms for the proposed collection(s) summarized in this notice, you may make your request using one of following:

1. Access CMS' Web site address at *http://www.cms.hhs.gov/PaperworkReductionActof1995.*
2. Email your request, including your address, phone number, OMB number, and CMS document identifier, to *Paperwork@cms.hhs.gov.*
3. Call the Reports Clearance Office at (410) 786–1326.

FOR FURTHER INFORMATION CONTACT: Reports Clearance Office at (410) 786–1326.

SUPPLEMENTARY INFORMATION: Under the Paperwork Reduction Act of 1995 (PRA) (44 U.S.C. 3501–3520), federal agencies must obtain approval from the Office of Management and Budget (OMB) for each collection of information they conduct or sponsor. The term ''collection of information'' is defined in 44 U.S.C. 3502(3) and 5 CFR 1320.3(c) and includes agency requests or requirements that members of the public submit reports, keep records, or provide information to a third party. Section 3506(c)(2)(A) of the PRA (44 U.S.C.

3506(c)(2)(A)) requires federal agencies to publish a 30-day notice in the **Federal Register** concerning each proposed collection of information, including each proposed extension or reinstatement of an existing collection of information, before submitting the collection to OMB for approval. To comply with this requirement, CMS is publishing this notice that summarizes the following proposed collection(s) of information for public comment:

1. *Type of Information Collection Request:* Revision of a currently approved collection; *Title of Information Collection:* Part C Medicare Advantage Reporting Requirements and Supporting Regulations; *Use:* There are a number of information users of Part C reporting data, including our central and regional office staff that use this information to monitor health plans and to hold them accountable for their performance, researchers, and other government agencies such as the Government Accounting Office. Health plans can use this information to measure and benchmark their performance.

Based on internal review, this notice withdraws a portion of a prior notice (August 24, 2015) concerning the same subject matter and corrects that notice by adding a new requirement which was inadvertently omitted from that notice. Specifically, we propose to add a new Payments to Providers reporting section to capture data related to MA organizations' value-based payments. Upon OMB approval, the Payments to Providers section would add 10 data elements.

HHS has developed four categories of value based payment: (1) Fee-for-service with no link to quality; (2) fee-for-service with a link to quality; (30 alternative payment models built on fee-for-service architecture; and (4) population-based payment. To compliment HHS' action, CMS is seeking to collect data from MA organizations about the proportion of their payments to providers made based on these four categories. The collected information would help us understand the extent and use of alternate payment models in the MA industry.

Form Number: CMS–10261 (OMB Control Number 0938–1054); *Frequency:* Yearly and semi-annually; *Affected Public:* Private sector (business or other for-profits); *Number of Respondents:* 561; *Total Annual Responses:* 3,508; *Total Annual Hours:* 182,023. (For policy questions regarding this collection contact Terry Lied at 410–786–8973).

Partial Withdrawal of Previous Notice

This document also withdraws a portion of a prior notice concerning the same CMS–10261-specific subject matter.

Specifically, on page 51276, in the second column, in the second paragraph, information collection CMS–10261 (OMB Control Number 0938–1054) that published in the **Federal Register** on August 24, 2015 (80 FR 51275) is hereby withdrawn.

Dated: September 15, 2015.

William N. Parham, III,

Director, Paperwork Reduction Staff, Office of Strategic Operations and Regulatory Affairs.

[FR Doc. 2015–23482 Filed 9–17–15; 8:45 am]

BILLING CODE 4120–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Food and Drug Administration

[Docket No. FDA–2015–N–3230]

Consumer Comments—Public Posting and Availability of Comments Submitted to Food and Drug Administration Dockets

AGENCY: Food and Drug Administration, HHS.

ACTION: Notice.

SUMMARY: The Food and Drug Administration (FDA or Agency) is changing the Agency's long standing practice of not publically posting on *http://www.regulations.gov* comments submitted by individuals in their individual capacity. These are generally comments from people who self-identify as an ''individual consumer'' under the field titled ''Category (Required)'' on the ''Your Information'' page on *http://www.regulations.gov.* Changing FDA's practice to routinely post these comments, as we do other comments, will increase the transparency and public utility of FDA's public dockets. It will better enable our public dockets to function as intended: To share information and encourage an open exchange of ideas.

DATES: All comments submitted to any FDA docket on or after October 15, 2015, will be publically posted, unless otherwise determined not to be subject to posting as described in the **SUPPLEMENTARY INFORMATION** section.

FOR FURTHER INFORMATION CONTACT: Kenneth R. Cohen, Food and Drug Administration, 10903 New Hampshire Ave., Bldg. 32, Rm. 3324, Silver Spring, MD 20993–0002, 301–796–7001.

SUPPLEMENTARY INFORMATION:

I. Background

Historically, FDA generally has not publicly posted on *http://www.regulations.gov* comments submitted by individuals in their individual capacity (and not on behalf of an organization, corporation, or other entity). For comments submitted through *http://www.regulations.gov,* for example, such comments are identified as ''Individual Consumer'' under the field titled ''Category (Required) '' on the ''Your Information'' page. This non-posting practice has applied only to individual consumer comments which otherwise would be displayed on *http://www.regulations.gov.* These comments have been placed in the official FDA docket and are publicly available in FDA's Reading Room or through Freedom of Information Act requests and have been considered by the Agency in finalizing its regulatory actions.

FDA is changing this practice and will post such consumer comments on *http://www.regulations.gov,* as it posts other comments. FDA has made this change so that its public dockets better serve their purpose of promoting transparency and the sharing of information.

In 1995, FDA explained that it routinely reviewed all comments for obvious confidential information before placing the comments in the docket (60 FR 66982), but this practice is no longer feasible given factors such as the volume of comments FDA receives and the adoption of a government-wide electronic portal system for submitting and posting comments at *http://www.regulations.gov.* FDA developed the practice of not posting individual consumer comments largely because of concerns about disclosing personal information of individuals who may not have realized, when submitting their comments, that their name, address, and other identifying information would be publicly viewable. This public viewability became more obvious as the Internet gained popularity and particularly when FDA dockets system was merged with the government-wide portal system for submission of all public comments on government regulatory actions at *http://www.regulations.gov* in 2007. This practice has been precautionary because, as FDA has stated previously, ''there can be no reasonable expectation of confidentiality for information submitted to a public docket in a rulemaking proceeding.'' [1] With the advent of *http://www.regulations.gov,*

[1] 60 FR 66981, at 66982 (December 27, 1995).

FDA selected ''individual consumer'' comments for non-posting because of previous concerns raised by individuals and the conclusion that such commenters may not be as familiar with the regulatory process and the public nature of dockets as are other entities, such as regulated industry.

In recent years, FDA has occasionally made exceptions to this non-posting practice, typically using the COMMENTS section in a particular **Federal Register** document to alert the public that all comments were subject to public posting. FDA **Federal Register** documents, requesting or providing for the submission of comments, published subsequent to this notice will contain new instructions and information concerning the posting of comments submitted to that particular docket.

This change fulfills a recommendation from the 2010 FDA Transparency Initiative [2] and aligns with a 2013 recommendation from the Administrative Conference of the United States that ''[a]gencies should manage their public rulemaking dockets to achieve maximum public disclosure'' consistent with legal limitations and other claims of privilege.[3] It also furthers an objective in Executive Order 13563,[4] which directs Agencies to base their regulations on ''public participation and an open exchange of ideas.''

II. Consumer Comments and Confidential Information

The commenter is solely responsible for ensuring that the submitted comment does not include any confidential information that the commenter or a third party may not wish to be posted, such as private medical information, the commenter's or anyone else's Social Security number, or confidential business information, such as a manufacturing process. If a name, contact information, or other information that identifies the commenter is included in the body of the submitted comment, that information will be posted on *http://www.regulations.gov.* FDA will post comments, as well as any attachments submitted electronically, on *http://www.regulations.gov,* along with the State/Province and country (if provided), the name of the commenter's representative (if any), and the category selected to identify the commenter (*e.g.,* individual, consumer, academic, industry).

The Agency expects that only in exceptional instances would a comment need to include private, personal, or confidential information. If a comment is submitted with confidential information that the commenter does not wish to be made available to the public, the comment would be submitted as a written/paper submission and in the manner detailed in the applicable **Federal Register** document. For written/paper comments submitted containing confidential information, FDA will post the redacted/blacked out version of the comment including any attachments submitted by the commenter. The unredacted copy will not be posted, assuming the commenter follows the instructions in the applicable **Federal Register** document. Any information marked as confidential will not be disclosed except in accordance with § 10.20 (21 CFR 10.20) and other applicable disclosure law.

FDA will include new information and standard instructions for submitting comments in all **Federal Register** documents requesting or providing for the submission of comments. The instructions will explain how to submit comments to the docket on that particular document via electronic means and also will explain the process for submission of comments, in written/paper format, that the commenter wishes to mark as confidential.

III. Date of Implementation

All comments submitted electronically through *http://www.regulations.gov* to any FDA docket, existing or new, after October 15, 2015, will be posted to the applicable docket and publicly viewable on *http://www.regulations.gov.* All comments submitted by mail or delivery to the Division of Dockets Management in written/paper format to any FDA docket, existing or new, after October 15, 2015, will be posted to the applicable docket and publicly viewable on *http://www.regulations.gov* unless submitted under the following conditions: (1) The written/paper submission is marked as confidential, and (2) the submitter provides an unredacted and a redacted version; the redacted version must have the information claimed as confidential redacted/blacked out. If submitted under these conditions, only the redacted/blacked out written/paper submission will be posted publicly on *http://www.regulations.gov,* except as otherwise provided by § 10.20 or other law.

Dated: September 14, 2015.

Leslie Kux,

Associate Commissioner for Policy.

[FR Doc. 2015–23389 Filed 9–17–15; 8:45 am]

BILLING CODE 4164–01–P

[2] ''FDA Transparency Initiative: Draft Proposals for Public Comment Regarding Disclosure Policies of the U.S. Food and Drug Administration,'' May 2010, available at *www.fda.gov/AboutFDA/Transparency/PublicDisclosure* (p. 4).

[3] Recommendation No. 2013–4, available at *http://www.acus.gov/recommendation/administrative-record-informal-rulemaking.*

[4] Executive Order 13563, available at *http://www.gpo.gov/fdsys/pkg/FR-2011-01-21/pdf/2011-1385.pdf.*

DEPARTMENT OF HEALTH AND HUMAN SERVICES

Office of the Secretary

[Document Identifier: HHS–OS–0990–0279–30D]

Agency Information Collection Activities; Submission to OMB for Review and Approval; Public Comment Request

AGENCY: Office of the Secretary, HHS.

ACTION: Notice.

SUMMARY: In compliance with section 3507(a)(1)(D) of the Paperwork Reduction Act of 1995, the Office of the Secretary (OS), Department of Health and Human Services, has submitted an Information Collection Request (ICR), described below, to the Office of Management and Budget (OMB) for review and approval. The ICR is for renewal of the approved information collection assigned OMB control number 0990–0279, scheduled to expire on September 30, 2015. Comments submitted during the first public review of this ICR will be provided to OMB. OMB will accept further comments from the public on this ICR during the review and approval period.

DATES: Comments on the ICR must be received on or before October 19, 2015.

ADDRESSES: Submit your comments to *OIRA_submission@omb.eop.gov* or via facsimile to (202) 395–5806.

FOR FURTHER INFORMATION CONTACT: Information Collection Clearance staff, *Information.CollectionClearance@hhs.gov* or (202) 690–6162.

SUPPLEMENTARY INFORMATION: When submitting comments or requesting information, please include the OMB control number 0990–0279 and document identifier HHS–OS–30D for reference.

Information Collection Request Title: Institutional Review Board Form—OMB No. 0990–0279, Assistant Secretary for Health, Office for Human Research Protections.

Abstract: Section 491(a) of Public Law 99–158 states that the Secretary of HHS shall by regulation require that each entity applying for HHS support (*e.g.,* a grant, contract, or cooperative agreement) to conduct research involving human subjects submit to HHS assurances satisfactory to the Secretary that it has established an institutional review board (IRB) to review the research in order to ensure protection of the rights and welfare of the human research subjects. IRBs are boards, committees, or groups formally designated by an entity to review, approve, and have continuing oversight of research involving human subjects.

The Office for Human Research Protections (OHRP) and the Food and Drug Administration (FDA) are requesting a three-year extension of the OMB No. 0990–0279, Institutional Review Board (IRB) Registration Form. This form was modified in 2009 to be consistent with IRB registration requirements, 45 CFR 46, subpart E and 21 CFR 56.106 that were adopted in July 2009 OHRP and FDA, respectively.

Need and Proposed Use of the Information: The information collected through the Institutional Review Board registration collection requirements is the minimum necessary to satisfy the registration requirements of Section 491(a) of the Public Health Service Act, 45 CFR part 46, subpart E and 21 CFR 56.106.

Likely Respondents: Institutions or organizations operating IRBs that review human subjects research conducted or supported by HHS, or, in the case of FDA's regulations, IRBs in the United States that review clinical investigations regulated by FDA under sections 505(i) or 520(g) of the Federal Food, Drug and Cosmetic Act; and, IRBs in the United States that review clinical investigations that are intended to support applications for research or marketing permits for FDA-regulated products.

Burden Statement: The burden estimates for the IRB registration form include those approved by OMB in March 2015 under Control Number 0990–0263, the Assurance Identification/IRB Certification/ Declaration of Exemption form (former Optional Form 310). Those burden estimates are not included as part of the burden estimate presented below.

ESTIMATED ANNUALIZED BURDEN TABLE

Form name	Number of respondents	Number of responses per respondent	Average burden per response (in hours)	Total burden hours
IRB Registration 0990–0279	5,900	2	1	11,800
New Registratration	500	2	1	1,000
Total				12,800

Darius Taylor,

Information Collection Clearance Officer.

[FR Doc. 2015–23453 Filed 9–17–15; 8:45 am]

BILLING CODE 4150–28–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Bethesda Campus Chilled Water System Improvements Record of Decision

SUMMARY: The Department of Health and Human Services, the National Institutes of Health (NIH), has decided, after completion of a Final Environmental Impact Statement (FEIS) and a thorough consideration of the public comments on the Draft EIS, to implement the Proposed Action, referred to as the Proposed Action in the Final EIS. This action is to install a Thermal Energy Storage System and an Industrial Water Storage System to provide sufficient storage capacity to meet two days of chilled water demand and two days of industrial water demand should an outside disturbance interrupt the water supply.

FOR FURTHER INFORMATION CONTACT: Valerie Nottingham, Deputy Director, DEP, ORF, NIH, Building 13, Room 2S11, 9000 Rockville Pike, Bethesda, MD 20892, Phone 301–496–7775, *nihnepa@mail.nih.gov. Responsible Official:* Daniel G. Wheeland, Director, Office of Research Facilities (ORF) Development and Operations, NIH.

SUPPLEMENTARY INFORMATION:

Decision

After careful review of the environmental consequences in the Final Environmental Impact Statement for the Chilled Water System Improvements, National Institutes of Health, and consideration of public comment throughout the NEPA process, the NIH has decided to implement the Proposed Action described below as the Selected Alternative.

Selected Alternative

The Selected Alternative would implement chilled water system improvements that would enable the NIH to adequately accomplish the project goals. This would include sufficient storage capacity to meet two days of chilled water demand and two days of industrial water demand should an outside disturbance interrupt the normal supply of water by the WSSC.

Elements of the Chilled Water System Improvements project that the NIH would implement under the Proposed Action include the following:

Thermal Energy Storage System

This system would be located at the Building 34 site and would store up to approximately nine million gallons of chilled water. Components of the system would include a storage tank, at or partially below-grade, with a footprint of approximately 12,000 SF; a pump house building with a footprint of approximately 5,000 SF or less; support equipment, such as pumps, valves, piping, controls, and an emergency generator; and security fencing, lighting, and other site improvements. The NIH would use this system to meet chilled water demands within the Campus.

Industrial Water Storage System

This system would be located at the Parking Lot 41 site and would store up to approximately five million gallons of industrial water. Industrial water is water that the CUP utilizes to generate steam or chilled water. Components of the system would include a storage tank, partially below-grade; a pump house building with a footprint of approximately 5,000 SF; support equipment, such as pumps, valves, variable frequency drivers, electrical equipment, switchgear, piping, controls, instrumentation, and an emergency generator; and security fencing, lighting, and other site improvements. The NIH would use this system to ensure an adequate supply of water to the chillers.

Other Supporting Infrastructure

The Thermal Energy Storage System and the Industrial Water Storage System would each require new or upgraded utility infrastructure at locations outside the limit of disturbance for each system. Potential locations for many components of this infrastructure have been identified during the planning process. However, precise details including piping locations and sizes are not fully developed. Examples of the types of infrastructure that the NIH may install or upgrade include additional equipment (*e.g.*, pumps, variable frequency drives, electrical equipment, switchgear, emergency generator, control valves, backflow preventers, pressure reducing valves, controls, and instrumentation); other utility buildings; aboveground or buried piping; aboveground or buried utilities; and site improvements (*e.g.*, repairs to existing features, new concrete slabs).

Alternatives Considered

The Proposed Action, Alternative Action and No Action Alternative were the three alternatives analyzed in the Final EIS. The Alternative Action would implement water infrastructure improvements that would enable the NIH to adequately accomplish the project goals. The characteristics, features, and location of the Thermal Energy Storage System would be identical to the Proposed Action. What separates the Alternative Action from the Proposed is the proposal of the Potable Water Storage System. The Potable Water Storage System would store up to nine million gallons of potable water to ensure an adequate supply of industrial water to the chillers and for potable water requirements on the Campus. The proposed location for the Potable Water Storage System would be the same as that described for the Industrial Water Storage System under the Proposed Action. The characteristics and components of the Potable Water Storage System would be similar to the Industrial Water Storage System, except that the storage tank would be larger. The tank would be about 90 feet in height, which is similar to the planned height of MLP–12 once fully built. The pump house, support equipment, and utilities and site improvements would otherwise be identical to the described features of the Industrial Water Storage Tank.

Factors Involved in the Decision

The NIH prefers the Proposed Action over the Alternative Action because the Alternative Action would require the NIH to become a continuous water source, which would incur more upfront and ongoing costs for treatment, maintenance, and monitoring of the campus potable water system. Additionally, relative to the Alternative Action, the Proposed Action would retain more connections to WSSC water mains (for redundancy), would not require installation and operation of pumps to maintain adequate pressure for fire service, would maintain existing flow dynamics of potable water within the Campus, and would require less construction (and therefore pose less potential for construction-related impacts to campus neighbors).

Resources Impacted

The Final EIS describes potential environmental effects of the Selected Alternative. These potential effects are documented in Chapter 3 of the Final EIS. Any potential adverse environmental effects will be avoided or mitigated through design elements, procedures, and compliance with regulatory and NIH requirements. Potential impacts on air quality are all within government standards (federal, state, and local). NIH does not expect significant negative effects on the environment or on the citizens of Bethesda from construction and operation at NIH.

Summary of Impacts

The following is a summary of potential impacts resulting from the Selected Alternative that the NIH considered when making its decision. No adverse cumulative effects have been identified during the NEPA process. Likewise, no unavoidable or adverse impacts from implementation of the Selected Action have been identified. The Selected Action will be beneficial to the long-term productivity of the national and world health communities. Biomedical research conducted at the NIH facility will have the potential to advance techniques in disease prevention, develop disease immunizations, and prepare defenses against naturally emerging and re-emerging diseases and against bioweapons. Additionally, the local community will benefit from increased employment, income and, government and public finance.

Housing

Implementation of the Selected Alternative would result in temporary minor impacts on the population and the availability of housing, due to construction workers who might temporarily relocate to the area.

Education

Educational resources in the area surrounding the Campus include public schools, the Uniformed Services University of the Health Sciences (located on NSA Bethesda), and the Foundation for Advanced Education in the Sciences (located at 9109 Old Georgetown Road). Public schools near the Campus include three high schools, five middle schools, and nineteen elementary schools. Implementation of the Selected Alternative will not have a significant impact to education.

Transportation

Implementation of the Selected Alternative would result in minor temporary impacts to off-campus roads, transit, and traffic due to construction activities. This would include additional traffic due to construction vehicles as well as shifts in employee traffic patterns. Implementation of the Selected Alternative would involve the construction of approximately 1–3 parking spaces to accommodate access for operation or maintenance vehicles. The construction of the Industrial Water Storage System would reduce parking capacity at Parking Lot 41 by approximately 90 parking spaces. In total, this will lead to a net decrease of approximately 90 parking spaces.

Security

Implantation of the Selected Alternative may have the NIH install security fencing to prevent unauthorized access to the tanks. There would be no significant impacts to security.

Employment

The Selected Alternative would result in minor benefits to the local economy during construction activities (*e.g.*, meals and incidentals for construction workers). The Proposed Action would not result in a permanent change in job availability at the Campus or associated effects on the local economy.

Environmental Justice

Bethesda as a whole has relatively low proportions of minority, or low-income populations. Although there are areas of higher minority populations (30 to 35 percent) adjacent to the Campus, the percent minority is still low relative to Montgomery County (40.5 percent) and Maryland (37.9 percent). Impacts to social resources such as population and housing would be minor and temporary.

Visual Quality

The Selected Alternative would result in minor adverse impacts to external viewscapes. Existing topographical features and vegetation that largely block many potential views from adjacent neighborhoods would not be significantly altered as a result of the Selected Alternative.

The Selected Alternative would result in minor to moderate adverse impacts to internal viewscapes. The construction of the Industrial Water Storage System would require removal of a grassy area with trees. This would result in a minor negative impact to the visual character of that area of the Campus. The construction of the Thermal Energy Storage System would have a moderate adverse impact, as the associated tank would be viewable from the central part of the Campus. Also, implementation of the Selected Alternative could result in removal of existing trees and vegetation from the Building 34 site that currently reduces views from the north. The scale of this potential impact is somewhat tempered as the tank would be adjacent to a parking garage and the CUP, so it would not be entirely out of character with surrounding structures.

Under the Selected Alternative, all structures would be constructed to a height that does not exceed the Master Plan building height guidance. Construction of the Industrial Water Storage System into the hillside slope near Parking Lot 41 would be consistent with Master Plan guidance for minimizing the visual impact of new construction.

Noise

Implementation of the Selected Alternative would result in temporary minor noise impacts due to construction activities as well as long-term moderate noise impacts due to operational changes at the CUP.

Air Quality

Implementation of the Selected Alternative would result in minor direct and indirect impacts to air quality.

Greenhouse Gas Emissions

Construction and demolition activities would generate temporary greenhouse gas (GHG) emissions, while periodic emergency generator use, would generate recurring GHG emissions. Current GHG methodologies outlined in the TSD do not describe how to account for construction activities; therefore, they are not included in the current NIH GHG inventory. NIH would strive to minimize GHG emissions by implementing construction, renovation, and demolition best practices.

Stormwater

Temporary Construction Impacts

Implementation of the Selected Alternative would result in minor temporary impacts to stormwater quantity and quality due to earth disturbances during construction activities. The Limit of Disturbance (LOD) for the Selected Alternative would be approximately 467,000 SF of earth during construction activities.

Potential erosion and sediment runoff impacts would be mitigated through stormwater management, including the development of an erosion and sediment control plan that is approved by MDE. The construction of the Thermal Energy Storage System and Industrial Water Storage System would each disturb more than one acre and therefore would obtain coverage under the MDE 2014 General Permit for Stormwater Associated with Construction Activity. As a result, construction activities under the Proposed Action would have a minor impact on stormwater quality.

Long-Term Stormwater Management

Implementation of the Selected Alternative would result in minor long-term stormwater management impacts. The Selected Alternative would increase impervious surface at the Campus by approximately 153,000 SF, which would increase runoff within the Rock Creek Watershed relative to baseline conditions. However, the construction of the Thermal Energy Storage System and Industrial Water Storage System would each disturb greater than 5,000 SF, and therefore site design would be required to meet The Energy Independence and Security Act of 2007 (EISA 2007) Section 438 requirements to restore each site to predevelopment conditions. This requirement would minimize hydrologic impacts resulting from increased stormwater runoff volumes, such as damage to storm sewer infrastructure, increased likelihood of flooding, and increased erosion.

The Selected Alternative would require permanent site stormwater management to control runoff and provide water quality treatment per federal and Maryland stormwater regulations. Long-term stormwater management facilities would be designed and installed per an MDE approved stormwater management plan. The NIH would incorporate appropriate and feasible Environmental Site Design (ESD) practices into the project designs to restore the predevelopment hydrology to the maximum extent technically feasible. Overall, these ESD practices would reduce runoff volume and rate, disperse flow, remove pollutants, and provide for groundwater recharge by facilitating infiltration into the soil.

Construction of the Industrial Water Storage System and Thermal Energy Storage System would likely incorporate bioretention areas including stormwater planter boxes. These vegetated areas would infiltrate runoff from impervious surfaces at the site, reducing the quantity of stormwater runoff and improving the water quality.

The Selected Alternative would not impact coverage under the Campus's Municipal Separate Storm Sewer System, MS4 permit.

Historic Resources

Construction of the Thermal Energy Storage System and associated infrastructure would result in temporary construction impacts (*e.g.*, noise) and a permanent change in the appearance of the Building 34 site. These impacts would be perceptible from the rear of the historic Biologics Standards Laboratory and Annex (Buildings 29 and 29A), located north of the project site. The new infrastructure would also result in a minor change in the appearance of the Campus when viewed from the historic National Library of Medicine (NLM) complex (Buildings 38 and 38A). Additionally, construction of the Industrial Water Storage System may result in a minor change in the appearance of the Campus when viewed from the upper levels of Building 38A. Construction of these new facilities, however, would not affect the integrity of setting of these historic properties; would not obscure or compromise their original design intent; and would not otherwise affect the characteristics that qualify these historic properties for listing in the National Register.

Based on this analysis, the NIH has determined that the Selected Alternative would not adversely affect any historic properties or MIHP-listed properties. Pursuant to Section 106 of the NHPA, the NIH initiated consultation with the MD SHPO to obtain their concurrence with this finding. MD SHPO's concurrence of no adverse effect was received on 20 April 2015.

Practicable Means To Avoid or Minimize Potential Environmental Harm From the Selected Alternative

All practicable means to avoid or minimize adverse environmental effects from the Selected Alternative have been identified and incorporated into the action. The proposed Chilled Water System Improvement construction will be subject to the existing NIH pollution prevention, waste management, and safety, security, and emergency response procedures as well as existing environmental permits. Best management practices, spill prevention and control, and stormwater management plans will be followed to appropriately address the construction and operation of the new Chilled Water

System and comply with applicable regulatory and NIH requirements. No additional mitigation measures have been identified.

Pollution Prevention

Air quality permit standards will be met, as will all federal, state, and local requirements to protect the environment and public health.

Conclusion

Based upon review and careful consideration, the NIH has decided to implement the Selected Alternative for a Chilled Water System Improvement System located in Bethesda, Maryland. The decision accounts for a potential outside disturbance interrupting the campus water supply. The system will provide sufficient storage capacity to meet two days of chilled water demand and two days of industrial water demand should an interruption occur.

The decision was based upon review and careful consideration of the impacts identified in the Final EIS and public comments received throughout the NEPA process.

Dated: September 8, 2015.

Daniel G. Wheeland,

Director, Office of Research Facilities Development and Operations, National Institutes of Health.

[FR Doc. 2015–23487 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Neurological Sciences Training Initial Review Group, NST–1 Subcommittee.
Date: October 13–14, 2015.
Time: 8 a.m. to 6 p.m.
Agenda: To review and evaluate grant applications.
Place: Hyatt Regency Bethesda, One Bethesda Metro Center, 7400 Wisconsin Avenue, Bethesda, MD 20814.
Contact Person: Raul A. Saavedra, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, NINDS/NIH/DHHS/Neuroscience Center, 6001 Executive Boulevard, Suite 3208, MSC 9529, Bethesda, MD 20892–9529, 301–496–9223, *saavedrr@ninds.nih.gov.*

Name of Committee: Neurological Sciences Training Initial Review Group, NST–2 Subcommittee.
Date: October 26–27, 2015.
Time: 8 a.m. to 5 p.m.
Agenda: To review and evaluate grant applications.
Place: Hotel Monaco Alexandria, 480 King Street, Alexandria, VA 22314.
Contact Person: Elizabeth A. Webber Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, NINDS/NIH/DHHS/Neuroscience Center, 6001 Executive Boulevard, Suite 3208, MSC 9529, Bethesda, MD 20892–9529, 301–496–1917, *webbere@mail.nih.gov.*

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders A.
Date: October 27–28, 2015.
Time: 8 a.m. to 6 p.m.
Agenda: To review and evaluate grant applications.
Place: Admiral Fell Inn, 888 South Broadway, Baltimore, MD 21231.
Contact Person: Natalia Strunnikova, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, NINDS/NIH/DHHS/Neuroscience Center, 6001 Executive Boulevard, Suite 3208, MSC 9529, Bethesda, MD 20892–9529, 301–402–0288, *natalia.strunnikova@nih.gov.*

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders B.
Date: October 29, 2015.
Time: 8 a.m. to 6 p.m.
Agenda: To review and evaluate grant applications.
Place: Hotel Monaco Alexandria, 480 King Street, Alexandria, VA 22314.
Contact Person: Birgit Neuhuber, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, NINDS/NIH/DHHS/Neuroscience Center, 6001 Executive Boulevard, Suite 3208, MSC 9529, Bethesda, MD 20892–9529, 301–496–3562, *neuhuber@ninds.nih.gov.*

Name of Committee: National Institute of Neurological Disorders and Stroke Initial Review Group; Neurological Sciences and Disorders C.
Date: November 5–6, 2015.
Time: 8 a.m. to 6 p.m.
Agenda: To review and evaluate grant applications.
Place: Embassy Suites Alexandria, 1900 Diagonal Road, Alexandria, VA 22314.
Contact Person: William C. Benzing, Ph.D., Scientific Review Officer, Scientific Review Branch, Division of Extramural Research, NINDS/NIH/DHHS/Neuroscience Center, 6001 Executive Boulevard, Suite 3204, MSC 9529, Bethesda, MD 20892–9529, 301–496–0660, *benzingw@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.853, Clinical Research Related to Neurological Disorders; 93.854, Biological Basis Research in the Neurosciences, National Institutes of Health, HHS)

Dated: September 14, 2014.

Carolyn Baum,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–23444 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Mental Health; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute of Mental Health Special Emphasis Panel; Research Education Programs (R25).
Date: October 9, 2015.
Time: 2 p.m. to 4 p.m.
Agenda: To review and evaluate grant applications.
Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Telephone Conference Call).
Contact Person: Aileen Schulte, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6140, MSC 9608, Bethesda, MD 20892–9608, 301–443–1225, *aschulte@mail.nih.gov.*

Name of Committee: National Institute of Mental Health Special Emphasis Panel; Confirmatory Efficacy Clinical Trials of Non-Pharmacological Interventions for Mental Disorders.
Date: October 14, 2015.
Time: 11:30 a.m. to 3 p.m.
Agenda: To review and evaluate grant applications.
Place: National Institutes of Health, Neuroscience Center, 6001 Executive

Boulevard, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Marcy Ellen Burstein, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6143, MSC 9606, Bethesda, MD 20892–9606, 301–443–9699, *bursteinme@mail.nih.gov.*

Name of Committee: National Institute of Mental Health Special Emphasis Panel.

Date: October 14, 2015.

Time: 3 p.m. to 5 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, Neuroscience Center, 6001 Executive Boulevard, Rockville, MD 20852 (Telephone Conference Call).

Contact Person: Marcy Ellen Burstein, Ph.D., Scientific Review Officer, Division of Extramural Activities, National Institute of Mental Health, NIH, Neuroscience Center, 6001 Executive Blvd., Room 6143, MSC 9606, Bethesda, MD 20892–9606, 301–443–9699, *bursteinme@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program No. 93.242, Mental Health Research Grants, National Institutes of Health, HHS)

Dated: September 14, 2015.

Carolyn A. Baum,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–23445 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Office of the Director, National Institutes of Health Notice of Meeting

Pursuant to section 10(a) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Advisory Committee on Research on Women's Health.

The meeting will be open to the public, with attendance limited to space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should notify the Contact Person listed below in advance of the meeting.

Name of Committee: Advisory Committee on Research on Women's Health.

Date: October 20, 2015.

Open: 9:00 a.m. to 12:00 p.m.

Agenda: The Committee serves to advise and make recommendations to the Director, Office of Research on Women's Health (ORWH) on a broad range of topics.

Place: National Institutes of Health, Wilson Hall, Building 1, 1 Center Drive, Bethesda, MD 20892.

Open: 1:00 p.m. to 5:00 p.m.

Agenda: ORWH 25th Anniversary Celebration of Science.

Place: National Institutes of Health, Wilson Hall, Building 1, 1 Center Drive, Bethesda, MD 20892.

Contact Person: Terri L. Cornelison, MD, Ph.D., Executive Secretary, Office of Research on Women's Health, Office of the Director, National Institutes of Health, 6707 Democracy Blvd., Bethesda, MD 20817, (301) 402–1770, *terri.conelison@nih.gov.*

Any interested person may file written comments with the committee by forwarding the statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

In the interest of security, NIH has instituted stringent procedures for entrance onto the NIH campus. All visitor vehicles, including taxicabs, hotel, and airport shuttles will be inspected before being allowed on campus. Visitors will be asked to show one form of identification (for example, a government-issued photo ID, driver's license, or passport) and to state the purpose of their visit.

Information is also available on the Institute's/Center's home page: *www4.od.nih.gov/orwh/*, where an agenda and any additional information for the meeting will be posted when available.

(Catalogue of Federal Domestic Assistance Program Nos. 93.14, Intramural Research Training Award; 93.22, Clinical Research Loan Repayment Program for Individuals from Disadvantaged Backgrounds; 93.232, Loan Repayment Program for Research Generally; 93.39, Academic Research Enhancement Award; 93.936, NIH Acquired Immunodeficiency Syndrome Research Loan Repayment Program; 93.187, Undergraduate Scholarship Program for Individuals from Disadvantaged Backgrounds, National Institutes of Health, HHS)

Dated: September 14, 2014.

Carolyn Baum,

Program Analyst, Office of Federal Advisory Committee Police.

[FR Doc. 2015–23385 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Center for Scientific Review; Notice of Closed Meetings

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meetings.

The meetings will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Sleep and Circadian Processes.

Date: October 13–14, 2015.

Time: 8:00 a.m. to 6:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Virtual Meeting).

Contact Person: John Bishop, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5182, MSC 7844, Bethesda, MD 20892, (301) 408–9664, *bishopj@csr.nih.gov.*

Name of Committee: Oncology 2—Translational Clinical Integrated Review Group; Cancer Biomarkers Study Section.

Date: October 13–14, 2015.

Time: 8:00 a.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Embassy Suites at the Chevy Chase Pavilion, 4300 Military Road NW., Washington, DC 20015.

Contact Person: Lawrence Ka-Yun Ng, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 6152, MSC 7804, Bethesda, MD 20892, 301–357–9318, *ngkl@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; Member Conflict: Epilepsy and Neurodegenerative Diseases.

Date: October 14, 2015.

Time: 12:00 p.m. to 2:30 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institutes of Health, 6701 Rockledge Drive, Bethesda, MD 20892 (Telephone Conference Call).

Contact Person: Seetha Bhagavan, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 5194, MSC 7846, Bethesda, MD 20892, (301) 237–9838, *bhagavas@csr.nih.gov.*

Name of Committee: Infectious Diseases and Microbiology Integrated Review Group; Drug Discovery and Mechanisms of Antimicrobial Resistance Study Section.

Date: October 15–16, 2015.

Time: 8:30 a.m. to 6:30 p.m.

Agenda: To review and evaluate grant applications.

Place: Residence Inn Bethesda, 7335 Wisconsin Avenue, Bethesda, MD 20814.

Contact Person: Guangyong Ji, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 3188, MSC 7808, Bethesda, MD 20892, 301–435–1146, *jig@csr.nih.gov.*

Name of Committee: Center for Scientific Review Special Emphasis Panel; PAR15–162: Pilot Clinical Urology.

Date: October 22, 2015.

Time: 4:00 p.m. to 5:00 p.m.

Agenda: To review and evaluate grant applications.

Place: Crowne Plaza Washington National Airport, 1489 Jefferson Davis Hwy, Arlington, VA 22202.

Contact Person: Ryan G Morris, Ph.D., Scientific Review Officer, Center for Scientific Review, National Institutes of Health, 6701 Rockledge Drive, Room 4205, MSC 7814, Bethesda, MD 20892, 301–435–1501, *morrisr@csr.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.306, Comparative Medicine; 93.333, Clinical Research, 93.306, 93.333, 93.337, 93.393–93.396, 93.837–93.844, 93.846–93.878, 93.892, 93.893, National Institutes of Health, HHS)

Dated: September 14, 2015.

Melanie J. Gray,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–23387 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute of Neurological Disorders and Stroke; Notice of Meeting

Pursuant to section 10(a) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of a meeting of the Muscular Dystrophy Coordinating Committee (MDCC).

The meeting will be open to the public and accessible by live webcast.

Name of Committee: Muscular Dystrophy Coordinating Committee.

Type of meeting: Open Meeting.

Date: November 13, 2015.

Time: 8:30 a.m. to 4:30 p.m. *Eastern Time*—Approximate end time.

Agenda: The purpose of this meeting is to bring together committee members, representing government agencies, patient advocacy groups, other voluntary health organizations, and patients and their families to update one another on progress relevant to the Action Plan for the Muscular Dystrophies and to coordinate activities and discuss gaps and opportunities leading to better understanding of the muscular dystrophies, advances in treatments, and reduced disease burden. Prior to the meeting, an agenda will be posted to the MDCC meeting registration Web site: *https://meetings.ninds.nih.gov/meetings/MDCC13Nov2015/.*

Registration: To register, please go to: *https://meetings.ninds.nih.gov/meetings/MDCC13Nov2015/.*

Webcast Live: For those not able to attend in person, this meeting will be webcast at: *http://videocast.nih.gov/.*

Place: Neuroscience Center, Conference Room C/D, 6001 Executive Boulevard, Rockville, Maryland 20852.

Contact Person: Glen H. Nuckolls, Ph.D., Executive Secretary, Muscular Dystrophy Coordinating Committee, National Institute of Neurological Disorders and Stroke, NIH, 6001 Executive Boulevard, NSC 2203, Rockville, MD 20852, (301) 496–5739, *glen.nuckolls@ninds.nih.gov.*

Any member of the public interested in presenting oral comments to the committee may notify the Contact Person listed on this notice at least 10 days in advance of the meeting. Interested individuals and representatives of organizations may submit a letter of intent, a brief description of the organization represented, and a short description of the oral presentation. Only one representative of an organization may be allowed to present oral comments and if accepted by the committee, presentations may be limited to five minutes. Both printed and electronic copies are requested for the record. In addition, any interested person may file written comments with the committee by forwarding their statement to the Contact Person listed on this notice. The statement should include the name, address, telephone number and when applicable, the business or professional affiliation of the interested person.

Attendance is limited to seating space available. Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should inform the Contact Person listed above in advance of the meeting. All visitors must go through a security check at the meeting site to receive a visitor's badge. A valid, government issued photo ID must be presented before a visitor's badge can be issued. Further information can be found at the registration Web site: *https://meetings.ninds.nih.gov/meetings/MDCC13Nov2015/.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.853, Clinical Research Related to Neurological Disorders; 93.854, Biological Basis Research in the Neurosciences, National Institutes of Health, HHS)

Dated: September 14, 2015.

Carolyn Baum,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–23443 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

In Vitro to In Vivo Extrapolation for High Throughput Prioritization and Decision Making; Notice of Webinars and Public Workshop; Registration Information

SUMMARY: The National Toxicology Program (NTP) Interagency Center for the Evaluation of Alternative Toxicological Methods (NICEATM) and the U.S. Environmental Protection Agency (EPA) announce the workshop, ''*In Vitro* to *In Vivo* Extrapolation for High Throughput Prioritization and Decision Making.'' Attendees at the in-person workshop and four webinar presentations leading up to the workshop will discuss the state of the science and best practices for using *in vitro* to *in vivo* extrapolation (IVIVE) in a tiered risk decision context.

DATES: *Webinars:* October 7, 2015, at 11:00 a.m. Eastern Daylight Time (EDT); and November 4, 2015; December 2, 2015; and January 6, 2016; at 11:00 a.m. Eastern Standard Time (EST).

Webinar Registration: Deadline is two business days prior to each webinar.

Workshop: February 17–18, 2016, from 9:00 a.m. to approximately 5:00 p.m. (EST).

Workshop Registration: Deadline is February 5, 2016 at 5:00 p.m. (EST).

ADDRESSES:

Workshop Location: U.S. Environmental Protection Agency, 109 T.W. Alexander Dr., Durham, NC, 27709.

Web page: The preliminary agenda, registration, and other meeting materials will be available at *http://ntp.niehs.nih.gov/go/ivive-wksp-2016.*

FOR FURTHER INFORMATION CONTACT: Dr. Warren S. Casey, Director, NICEATM; email: *warren.casey@nih.gov;* telephone: (919) 316–4729.

SUPPLEMENTARY INFORMATION:

Background: Data from high throughput *in vitro* tests are being generated for many chemicals of environmental and commercial interest, with the expectation that *in vitro* assay data could ultimately be used to predict adverse effects of chemical exposures *in vivo.* Translating values obtained from *in vitro* assays into estimates of *in vivo* outcomes is a complex process involving the use of mathematical modeling and increasingly complex test systems. The series of four webinars and in-person workshop aim to address the capabilities and limitations of IVIVE within the context of risk decision-making.

The webinar series will present the current science, and the in-person workshop will facilitate discussions that follow-up and build on information presented in the webinars. During the workshop, participants will (1) review the state of the science to form recommendations on best practices for using IVIVE in chemical screening and risk-based decision making, (2) identify areas that require additional data and/or research, and (3) highlight examples of how best to apply IVIVE in a tiered risk decision-making strategy.

Preliminary Agenda and Other Meeting Information: A preliminary agenda and additional information will be available at *http://ntp.niehs.nih.gov/go/ivive-wksp-2016.*

Meeting and Registration: This workshop is open to the public, free of charge, with attendance limited only by the space available. Registration is required to attend both the webinars and the workshop. Those persons attending the workshop should plan to participate in all four webinars. However, viewing the webinars does not require attendance at the workshop. Individuals who plan to attend the workshop must register at *http://ntp.niehs.nih.gov/go/ivive-wksp-2016* by February 5, 2016. Individuals who plan to participate in the webinars must register at *http://ntp.niehs.nih.gov/go/ivive-wksp-2016* two business days prior to the webinar date to ensure access. Please visit this Web page for the most current information about the webinars and workshop. For those who register, information about how to access the webinar will be emailed within two business days of each webinar.

Individuals with disabilities who need accommodation to participate in these events should contact Dr. Elizabeth Maull at phone: (919) 316–4668 or email: *maull@niehs.nih.gov.* TTY users should contact the Federal TTY Relay Service at (800) 877–8339. Requests should be made at least five business days in advance of the event. Visitor and security information for those attending the workshop can be found at *http://www2.epa.gov/aboutepa/about-epas-campus-research-triangle-park-rtp-north-carolina.*

Background Information on NICEATM: NICEATM conducts data analyses, workshops, independent validation studies, and other activities to assess new, revised, and alternative test methods and strategies. NICEATM also provides support for the Interagency Coordinating Committee on the Validation of Alternative Methods (ICCVAM). The ICCVAM Authorization Act of 2000 (42 U.S.C. 285*l*–3) provides authority for ICCVAM and NICEATM in the development of alternative test methods. Information about NICEATM and ICCVAM is found at *http://ntp.niehs.nih.gov/go/niceatm* and *http://ntp.niehs.nih.gov/go/iccvam,* respectively.

Dated: September 14, 2015.

John R. Bucher,

Associate Director, National Toxicology Program.

[FR Doc. 2015–23386 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

National Institute on Aging; Notice of Closed Meeting

Pursuant to section 10(d) of the Federal Advisory Committee Act, as amended (5 U.S.C. App.), notice is hereby given of the following meeting.

The meeting will be closed to the public in accordance with the provisions set forth in sections 552b(c)(4) and 552b(c)(6), Title 5 U.S.C., as amended. The grant applications and the discussions could disclose confidential trade secrets or commercial property such as patentable material, and personal information concerning individuals associated with the grant applications, the disclosure of which would constitute a clearly unwarranted invasion of personal privacy.

Name of Committee: National Institute on Aging Special Emphasis Panel; Aging of the Lung.

Date: October 20, 2015.

Time: 3:00 p.m. to 7:00 p.m.

Agenda: To review and evaluate grant applications.

Place: National Institute on Aging, Gateway Building, 2C212, 7201 Wisconsin Avenue, Bethesda, MD 20892, (Telephone Conference Call).

Contact Person: Maurizio Grimaldi, MD, Ph.D., Scientific Review Officer, National Institute on Aging, National Institutes of Health, 7201 Wisconsin Avenue, Room 2c218, Bethesda, MD 20892, 301–496–9374, *grimaldim2@mail.nih.gov.*

(Catalogue of Federal Domestic Assistance Program Nos. 93.866, Aging Research, National Institutes of Health, HHS)

Dated: September 14, 2015.

Melanie J. Gray,

Program Analyst, Office of Federal Advisory Committee Policy.

[FR Doc. 2015–23388 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HEALTH AND HUMAN SERVICES

National Institutes of Health

Submission for OMB Review; 30-Day Comment Request; United States and Global Human Influenza Surveillance in At-Risk Settings (NIAID)

SUMMARY: Under the provisions of Section 3507(a)(1)(D) of the Paperwork Reduction Act of 1995, the National Institutes of Health, has submitted to the Office of Management and Budget (OMB) a request for review and approval of the information collection listed below. This proposed information collection was previously published in the **Federal Register** on April 9, 2015, page 19090 and allowed 60-days for public comment. One comment was received. However, it was not applicable to this data collection. The purpose of this notice is to allow an additional 30 days for public comment. The National Institute of Allergy and Infectious Diseases (NIAID), National Institutes of Health, may not conduct or sponsor, and the respondent is not required to respond to, an information collection that has been extended, revised, or implemented on or after October 1, 1995, unless it displays a currently valid OMB control number.

Direct Comments to OMB: Written comments and/or suggestions regarding the item(s) contained in this notice, especially regarding the estimated public burden and associated response time, should be directed to the: Office of Management and Budget, Office of Regulatory Affairs, *OIRA_submission@omb.eop.gov* or by fax to 202–395–6974, Attention: NIH Desk Officer.

Comment Due Date: Comments regarding this information collection are best assured of having their full effect if received within 30 days of the date of this publication.

FOR FURTHER INFORMATION CONTACT: To obtain a copy of the data collection plans and instruments, or request more information on the proposed project, contact: Dr. Diane Post, Program Officer, Respiratory Diseases Branch, NIAID, NIH, 5601 Fishers Lane, Bethesda, MD or call non-toll-free number at 240–627–3348 or email your request, including your address to: *postd@niaid.nih.gov.* Formal requests for additional plans and instruments must be requested in writing.

Proposed Collection: United States and Global Human Influenza Surveillance in at-Risk Settings, 0925—NEW, National Institute of Allergies and Infectious Diseases (NIAID), National Institutes of Health (NIH).

Need and Use of Information Collection: These studies will identify individuals with or at risk for influenza through focused surveillance in at-risk settings within the United States and internationally, rapidly identify circulating influenza strains to identify those with pandemic potential and create an invaluable bank of human samples from influenza patients to allow the characterization of the determinants of influenza transmission to and among humans, the immune response to influenza, and the basis of severe disease—critical knowledge gaps impacting effectiveness of decision-making around patient care and pandemic preparedness. These studies will provide insight into viral and host determinants that may be contributing to the transmission of influenza, immune response to influenza, and severity of influenza and associated morbidity and mortality.

OMB approval is requested for 3 years. There are no costs to respondents other than their time. The total estimated annualized burden hours for the entire 3 year request are 17334.

ESTIMATED ANNUALIZED BURDEN HOURS

Type of respondents	Estimates of hour burden				
	Form name	Number of respondents	Frequency of response	Average time per response	Annual hour burden
Hospital/care setting patients	Informed Consent Form	1600	1	10/60	267
	Form 1a Screening and enrollment log (Attachment 3).		1	10/60	267
	Form 2a Eligibility Checklist (Attachment 4)		1	10/60	267
	Form 3a Subject Identification (Attachment 5).		1	10/60	267
	Form 4a Demographic and Exposure Information (Attachment 6).		1	10/60	267
	Form 5a Current Symptoms (Attachment 7)		1	10/60	267
	Form 6a Medical History (Attachment 8)		1	10/60	267
	Form 8a Follow Up Assessment (Attachment 10).		4	10/60	1,067
Human Animal-interface patients.	Informed Consent Form	900	1	10/60	150
	Form 1a Screening and enrollment log (Attachment 3).		1	10/60	150
	Form 2a Eligibility Checklist (Attachment 4)		1	10/60	150
	Form 3a Subject Identification (Attachment 5).		1	10/60	150
	Form 4a Demographic and Exposure Information (Attachment 6).		1	10/60	150
	Form 5a Current Symptoms (Attachment 7)		25	10/60	3,750
	Form 6a Medical History (Attachment 8)		1	10/60	150
	Form 8a Follow Up Assessment (Attachment 10).		25	10/60	3,750
Household Surveillance patients.	Informed Consent Form	500	1	10/60	83
	Form 1a Screening and enrollment log (Attachment 3).		1	10/60	83
	Form 2a Eligibility Checklist (Attachment 4)		1	10/60	83
	Form 3a Subject Identification (Attachment 5).		1	10/60	83
	Form 4a Demographic and Exposure Information (Attachment 6).		1	10/60	83
	Form 5a Current Symptoms (Attachment 7)		6	10/60	500
	Form 6a Medical History (Attachment 8)		1	10/60	83
	Form 8a Follow Up Assessment (Attachment 10).		6	10/60	500
Study Staff	Informed Consent Form	5	600	10/60	500
	Form 7a Enrollment Specimen Collection (Attachment 9).		600	10/60	500
	Form 9a ED Chart Review (Attachment 11)		600	10/60	500
	Form 10a Chart Review—Inpatient Hospitalization (Attachment 12).		600	10/60	500
	Form 11a Subject Withdrawal Form (Attachment 13).		600	10/60	500
	Form 12a Subject checklist (Attachment 14)		600	10/60	500
	Form 13A Enrollment Report (Attachment 15).		600	10/60	500
	Form 14A 10% Data accuracy report (Attachment 16).		600	10/60	500
	Form 15A—QC Checklist (Attachment 17)		600	10/60	500
Totals		3,005			17,334

Dated: September 10, 2015.

Dione Washington,

Project Clearance Liaison, NIAID, NIH.

[FR Doc. 2015–23479 Filed 9–17–15; 8:45 am]

BILLING CODE 4140–01–P

DEPARTMENT OF HOMELAND SECURITY

Coast Guard

[Docket No. USCG–2015–0672]

Commercial Fishing Safety Advisory Committee; Vacancies

AGENCY: Coast Guard, Department of Homeland Security.

ACTION: Request for applications.

SUMMARY: The Coast Guard seeks applications for membership on the Commercial Fishing Safety Advisory Committee. The Commercial Fishing Safety Advisory Committee provides advice and makes recommendations to the Coast Guard and the Department of Homeland Security on various matters relating to the safe operation of commercial fishing industry vessels.

DATES: Completed applications should reach the Coast Guard on or before November 17, 2015.

ADDRESSES: Applicants should send a cover letter expressing interest in an appointment to the Commercial Fishing Safety Advisory Committee that identifies which membership category the applicant is applying under, along with a resume detailing the applicant's experience via one of the following methods:

- *By mail:* Commandant (CG–CVC), Attn: Fishing Vessel Safety, U.S. Coast Guard Stop 7501, 2703 Martin Luther King Jr Ave. SE., Washington, DC 20593–7501.
- *By fax:* 202–372–8377.
- *By email: jack.a.kemerer@uscg.mil.*

FOR FURTHER INFORMATION CONTACT: Mr. Jack Kemerer, Alternate Designated Federal Officer, telephone at 202–372–1249, fax at 202–372–8377, or email at *jack.a.kemerer@uscg.mil.*

SUPPLEMENTARY INFORMATION: The Commercial Fishing Safety Advisory Committee is a federal advisory committee under the Federal Advisory Committee Act, title 5 United States Code Appendix. The Coast Guard chartered the Commercial Fishing Safety Advisory Committee to provide advice on issues related to the safety of commercial fishing industry vessels regulated under chapter 45 of title 46, U.S.C., which includes uninspected fish catching vessels, fish processing vessels, and fish tender vessels. (See 46 U.S.C. 4508.)

The Commercial Fishing Safety Advisory Committee meets at least once a year. It may also meet for other extraordinary purposes. Its subcommittees or working groups may communicate throughout the year to prepare for meetings or develop proposals for the committee as a whole to address specific tasks.

Each member serves for a term of three years. An individual may be appointed to a term as a member more than once, but not more than two terms consecutively. All members serve at their own expense and receive no salary from the Federal Government, although travel reimbursement and per diem may be provided for called meetings.

The Coast Guard will consider applications for six (06) positions that expire or become vacant in May 2016 in the following categories:

(a) Commercial Fishing Industry representatives (*four* positions);

(b) General Public, (*one* position) particularly a person familiar with issues affecting fishing communities and families of fishermen; and

(c) A Naval Architect and Marine Engineer representative of commercial fishing vessels (*one* position).

If you are selected as a member from the general public, you will be appointed and serve as a Special Government Employee as defined in section 202(a) of title 18, United States Code. As a candidate for appointment as Special Government Employee, applicants are required to complete a Confidential Financial Disclosure Report (OGE Form 450). Coast Guard may not release the reports or the information in them to the public except under an order issued by a Federal court or as otherwise provided under the Privacy Act (5 U.S.C. 552a). Applicants can obtain this form by going to the Web site of the Office of Government Ethics (*www.oge.gov*), or by contacting the individual listed in **FOR FURTHER INFORMATION**. Applications for a member from the general public which are not accompanied by a completed OGE Form 450 will not be considered.

Registered lobbyists are not eligible to serve on federal advisory committees in an individual capacity. See ''Revised Guidance on Appointment of Lobbyist to Federal Advisory Committees, Boards and Commission'' (79 CFR 47482, August 13, 2014). The position we list for a member from the general public would be someone appointed in their individual capacity and would be designated as a Special Government Employee as defined in 202(a), title 18, U.S.C. Registered lobbyists are lobbyists required to comply with provisions contained in the Lobbying Disclosure Act of 1995 (Pub. L. 104–65, as amended by title II of Pub. L. 110–81).

The Department of Homeland Security does not discriminate in selection of Committee members on the basis of race, color, religion, sex, national origin, political affiliation, sexual orientation, gender identity, marital status, disability and genetic information, age, membership in an employee organization, or any other non-merit factor. The Department of Homeland Security strives to achieve a widely diverse candidate pool for all of its recruitment actions.

If you are interested in applying to become a member of the Committee, send your cover letter and resume to Mr. Jack Kemerer, Commercial Fishing Safety Advisory Committee Alternate Designated Federal Officer, via one of the transmittal methods in the **ADDRESSES** section by the deadline in the **DATES** section. Indicate the position you wish to fill and specify your area of expertise, knowledge, and experience that qualify you for that position on the Commercial Fishing Safety Advisory Committee.

To visit our online docket, go to *http://www.regulations.gov,* enter the docket number for this notice (USCG–2015–0672) in the Search box, and click ''Search''. Please do not post your resume or OGE Form 450 on this site.

Dated: September 11, 2015.

V.B. Gifford, Jr.,

Captain, U.S. Coast Guard, Director of Inspections and Compliance.

[FR Doc. 2015–23488 Filed 9–17–15; 8:45 am]

BILLING CODE 9110–04–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5828–N–38]

Federal Property Suitable as Facilities to Assist the Homeless

AGENCY: Office of the Assistant Secretary for Community Planning and Development, HUD.

ACTION: Notice.

SUMMARY: This Notice identifies unutilized, underutilized, excess, and surplus Federal property reviewed by HUD for suitability for use to assist the homeless.

FOR FURTHER INFORMATION CONTACT: Juanita Perry, Department of Housing and Urban Development, 451 Seventh Street SW., Room 7266, Washington, DC 20410; telephone (202) 402–3970; TTY number for the hearing- and speech-impaired (202) 708–2565 (these telephone numbers are not toll-free), or call the toll-free Title V information line at 800–927–7588.

SUPPLEMENTARY INFORMATION: In accordance with 24 CFR part 581 and section 501 of the Stewart B. McKinney Homeless Assistance Act (42 U.S.C.

11411), as amended, HUD is publishing this Notice to identify Federal buildings and other real property that HUD has reviewed for suitability for use to assist the homeless. The properties were reviewed using information provided to HUD by Federal landholding agencies regarding unutilized and underutilized buildings and real property controlled by such agencies or by GSA regarding its inventory of excess or surplus Federal property. This Notice is also published in order to comply with the December 12, 1988 Court Order in *National Coalition for the Homeless* v. *Veterans Administration,* No. 88–2503–OG (D.D.C.).

Properties reviewed are listed in this Notice according to the following categories: Suitable/available, suitable/unavailable, and suitable/to be excess, and unsuitable. The properties listed in the three suitable categories have been reviewed by the landholding agencies, and each agency has transmitted to HUD: (1) Its intention to make the property available for use to assist the homeless, (2) its intention to declare the property excess to the agency's needs, or (3) a statement of the reasons that the property cannot be declared excess or made available for use as facilities to assist the homeless.

Properties listed as suitable/available will be available exclusively for homeless use for a period of 60 days from the date of this Notice. Where property is described as for ''off-site use only'' recipients of the property will be required to relocate the building to their own site at their own expense. Homeless assistance providers interested in any such property should send a written expression of interest to HHS, addressed to: Ms. Theresa M. Ritta, Chief Real Property Branch, the Department of Health and Human Services, Room 5B–17, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857, (301) 443–2265 (This is not a toll-free number.) HHS will mail to the interested provider an application packet, which will include instructions for completing the application. In order to maximize the opportunity to utilize a suitable property, providers should submit their written expressions of interest as soon as possible. For complete details concerning the processing of applications, the reader is encouraged to refer to the interim rule governing this program, 24 CFR part 581.

For properties listed as suitable/to be excess, that property may, if subsequently accepted as excess by GSA, be made available for use by the homeless in accordance with applicable law, subject to screening for other Federal use. At the appropriate time, HUD will publish the property in a Notice showing it as either suitable/available or suitable/unavailable.

For properties listed as suitable/unavailable, the landholding agency has decided that the property cannot be declared excess or made available for use to assist the homeless, and the property will not be available.

Properties listed as unsuitable will not be made available for any other purpose for 20 days from the date of this Notice. Homeless assistance providers interested in a review by HUD of the determination of unsuitability should call the toll free information line at 1–800–927–7588 for detailed instructions or write a letter to Ann Marie Oliva at the address listed at the beginning of this Notice. Included in the request for review should be the property address (including zip code), the date of publication in the **Federal Register**, the landholding agency, and the property number.

For more information regarding particular properties identified in this Notice (*i.e.,* acreage, floor plan, existing sanitary facilities, exact street address), providers should contact the appropriate landholding agencies at the following addresses: *Agriculture:* Ms. Debra Kerr, Department of Agriculture, Reporters Building, 300 7th Street SW., Room 300, Washington, DC 20024, (202) 720–8873; *Health and Human Services:* Ms. Theresa M. Ritta, Chief Real Property Branch, the Department of Health and Human Services, Room 5B–17, Parklawn Building, 5600 Fishers Lane, Rockville, MD 20857, (301) 443–2265; *Navy:* Mr. Steve Matteo, Department of the Navy, Asset Management; Division, Naval Facilities Engineering Command, Washington Navy Yard, 1330 Patterson Ave. SW., Suite 1000, Washington, DC 20374; (202) 685–9426 (These are not toll-free numbers).

Dated: September 10, 2015.

Brian P. Fitzmaurice,

Director, Division of Community Assistance, Office of Special Needs Assistance Programs.

TITLE V, FEDERAL SURPLUS PROPERTY PROGRAM Federal Register REPORT FOR 09/18/2015

Suitable/Available Properties

Building

California

2 Buildings
5050 Smokey Court
Camp Connell CA 95223
Landholding Agency: Agriculture
Property Number: 15201510014
Status: Excess
Directions: Site 5202, Bldg. 5002
Comments: Off-site removal; 48+yrs.old; wood structure; 528 sq. ft.; office; very poor conditions; no future agency need; contact Agriculture of more info.

Michigan

Bergland Middle Building
Bergland Cultural Center Site
Bergland MI 49910
Landholding Agency: Agriculture
Property Number: 15201430017
Status: Unutilized
Comments: 1,025 sq. ft., storage; 120+ months vacant; deteriorating; building on National Register Site; contact Agriculture for more information.

Ontonagon Ranger House
1205 Rockland Road
Ontonagon MI 49953
Landholding Agency: Agriculture
Property Number: 15201430018
Status: Unutilized
Comments: 1,570 sq. ft., residential; 96+ months vacant; poor conditions; contact Agriculture for more information.

Montana

Residential Garage W/1032
Infra #1500
Ant Flat Road
Eureka MT 95501
Landholding Agency: Agriculture
Property Number: 15201520025
Status: Excess
Comments: Off-site removal only; 61+ yrs. old; 491 sq. ft.; storage; contact Agriculture for more information.

2-Bedroom Family Dwelling
Infra. #1032
Ant Flat Road
Eureka MT 95501
Landholding Agency: Agriculture
Property Number: 15201520026
Status: Excess
Directions: Ant Flat Road
Comments: Off-site removal; 64+ yrs. old; 1,004 sq. ft.; residential; 30+ mos. vacant; experience extensive flood; damage which caused significant mold damage; contact Agriculture for more information.

New York

Hector Grazing Association
Hdgt. House
5046 Rt. 1 Searsburg Road
Hector NY 14886
Landholding Agency: Agriculture
Property Number: 15201510001
Status: Unutilized
Comments: 125+ yrs. Old; 1,000 sq. ft.; storage; residential; vacant 96 NOS; wood structure; repaired needed in 2006 totaled $89,000; contact Agric. For more info.

Oregon

XX334 GB Grizzly Communication
Bldg. 1560.005181 076630 00
Agness OR 97406
Landholding Agency: Agriculture
Property Number: 15201430020
Status: Excess
Directions: 25 sq. ft.; shed; 39+ yrs.-old; poor condition
Comments: Off-site removal only; restrictive removal due to constraints surrounding land/vegetation.

Washington

Beth Lake Comfort Station
1303.005031
Beth Lake Campground
Chesaw WA 98844
Landholding Agency: Agriculture
Property Number: 15201520029
Status: Unutilized
Directions: 0325–0765300
Comments: Off-site removal; 50+ yrs.; old; 900 sq. ft.; toilet; 24+ mos. Vacant; not needs replacing; no future agency need; contact Agriculture for more information.

Wisconsin

Luepke Way Garage
207 Luepke Way
Medford WI 54451
Landholding Agency: Agriculture
Property Number: 15201440005
Status: Unutilized
Comments: off-site removal only; no future agency need; 96+ months vacant; 576 sq. ft.; roof & siding in poor conditions; wood structure; contact Agriculture for more information

Clam Lake Warehouse #364
61766 Highway 77
Clam Lake WI 54517
Landholding Agency: Agriculture
Property Number: 15201510029
Status: Unutilized
Comments: Off-site removal only; no future agency need; 800 sq. ft.; storage; good condition; contact Agriculture for more information.

Unsuitable Properties

Building

Arkansas

NCTR—Building 6 30956
3900 NCTR Rd.
Jefferson AR 72079
Landholding Agency: HHS
Property Number: 57201530010
Status: Unutilized
Comments: research-based campus; highly classified; public access denied and no alternative method to gain access w/out compromising national security.
Reasons: Secured Area
NCTR-Building13 Administrative
30956
3900 NCTR Rd.
Jefferson AR 72079
Landholding Agency: HHS
Property Number: 57201530011
Status: Unutilized
Comments: Researched-based campus; highly classified; public access denied and no alternative to gain access w/out compromising national security
Reasons: Secured Area

Colorado

8 Buildings; East Portal Site
Gilpin County Road
Nederland CO
Landholding Agency: Agriculture
Property Number: 15201430019
Status: Excess
Directions: 176; 177; 178; 179; 180; 181; 182; 183
Comments: Documented deficiencies; structurally unsound extreme deterioration; clear threat of physical safety.
Reasons: Extensive deterioration

Idaho

Bonners Cook Trailer
Infra. #1413
Bonners Ferry Ranger District Admin. Site
Bonners Ferry ID
Landholding Agency: Agriculture
Property Number: 15201510025
Status: Excess
Comments: Documented deficiencies: roof collapsing; clear threat to personal safety.
Reasons: Extensive deterioration.

Maryland

NIHBC #34 + 34A
34 Service Drive West
Bethesda MD 20892
Landholding Agency: HHS
Property Number: 57201510001
Status: Unutilized
Directions: #40506–00–0034; #40506–00–0034A
Comments: Research based facility; Public access denied & no alter method to gain access w/out compromising Nat'l Security.
Reasons: Secured Area.

Michigan

Mio 7 Winowiecki Consumers Cab
Huron Nat'l Forest Old M–72
(Smith Bridge)
Grayling MI 49738
Landholding Agency: Agriculture
Property Number: 15201520003
Status: Unutilized
Comments: Documented deficiencies: documentation provided represents a clear threat to personal safety; significant rot in floor/roof structure; relocation will most likely result in the roof collapsing.
Reasons: Extensive deterioration.

Michigan

Mio 7 Winowiecki Consumers Lea
Huron National Forest Old M–72
(Smith Bridge)
Grayling MI 49738
Landholding Agency: Agriculture
Property Number: 15201520004
Status: Unutilized
Comments: Documented deficiencies: documentation provided represents a clear threat to personal safety; interior space of the structure cannot be made to comply w/ habitability requirements.
Reasons: Extensive deterioration.

Pennsylvania

4 Buildings
Cochrans Mills Rd.
Pittsburgh PA 15236
Landholding Agency: HHS
Property Number: 57201410002
Status: Underutilized
Directions: 3, 101, 140, 145
Comments: w/in CDC secured campus; public access denied and no alternative to gain access w/out compromising national security.
Reasons: Secured Area.

Texas

Building 46 ID 620240B046
2881 F&B Road
College Station TX 77845
Landholding Agency: Agriculture
Property Number: 15201520027
Status: Unutilized
Comments: Tin roof in poor condition; ceiling falling down; exterior walls are rotten & pulling apart from the floor & roof; floor beams are rotten and unable to support the floor structure.
Reasons: Extensive deterioration.

VIRGINIA

21 Buildings
Marine Corps Base
Quantico VA
Landholding Agency: Navy
Property Number: 77201530016
Status: Unutilized
Directions: 27010A; 27013A; 27014B; 27015C; 27017D; 27026A; 27026Q; 27030A; 27061A; 27064D; 2739; 27246; 27246A; 27280B; 27553; 27018A; 27035; 27036; 2704A; 27058; 27012B—200 sq. ft. for each building listed.
Comments: REDETERMINATION: documented deficiencies: severely dilapidated; structurally unsound; clear threat to physical safety.
Reasons: Extensive deterioration.

Wisconsin

Vanderveen Barn; Infra. #332
N15484 Shady Knoll Road
Park Falls WI 54552
Landholding Agency: Agriculture
Property Number: 15201440009
Status: Unutilized
Comments: Documented deficiencies: dilapidated; sections of missing/collapsing; clear threat to physical safety.
Reasons: Extensive deterioration.

[FR Doc. 2015–23139 Filed 9–17–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5871–N–02]

Notice of Regulatory Waiver Requests Granted for the Second Quarter of Calendar Year 2015

AGENCY: Office of the General Counsel, HUD.

ACTION: Notice.

SUMMARY: Section 106 of the Department of Housing and Urban Development Reform Act of 1989 (the HUD Reform Act) requires HUD to publish quarterly **Federal Register** notices of all regulatory waivers that HUD has approved. Each notice covers the quarterly period since the previous **Federal Register** notice. The purpose of this notice is to comply with the requirements of section 106 of the HUD Reform Act. This notice contains a list of regulatory waivers granted by HUD during the period beginning on April 1, 2015, and ending on June 30, 2015.

FOR FURTHER INFORMATION CONTACT: For general information about this notice, contact Camille E. Acevedo, Associate General Counsel for Legislation and Regulations, Department of Housing and Urban Development, 451 Seventh Street SW., Room 10282, Washington, DC 20410–0500, telephone 202–708–1793 (this is not a toll-free number). Persons with hearing- or speech-impairments may access this number through TTY by calling the toll-free Federal Relay Service at 800–877–8339.

For information concerning a particular waiver that was granted and for which public notice is provided in this document, contact the person whose name and address follow the description of the waiver granted in the accompanying list of waivers that have been granted in the second quarter of calendar year 2015.

SUPPLEMENTARY INFORMATION: Section 106 of the HUD Reform Act added a new section 7(q) to the Department of Housing and Urban Development Act (42 U.S.C. 3535(q)), which provides that:

1. Any waiver of a regulation must be in writing and must specify the grounds for approving the waiver;

2. Authority to approve a waiver of a regulation may be delegated by the Secretary only to an individual of Assistant Secretary or equivalent rank, and the person to whom authority to waive is delegated must also have authority to issue the particular regulation to be waived;

3. Not less than quarterly, the Secretary must notify the public of all waivers of regulations that HUD has approved, by publishing a notice in the **Federal Register**. These notices (each covering the period since the most recent previous notification) shall:

a. Identify the project, activity, or undertaking involved;

b. Describe the nature of the provision waived and the designation of the provision;

c. Indicate the name and title of the person who granted the waiver request;

d. Describe briefly the grounds for approval of the request; and

e. State how additional information about a particular waiver may be obtained.

Section 106 of the HUD Reform Act also contains requirements applicable to waivers of HUD handbook provisions that are not relevant to the purpose of this notice.

This notice follows procedures provided in HUD's Statement of Policy on Waiver of Regulations and Directives issued on April 22, 1991 (56 FR 16337). In accordance with those procedures and with the requirements of section 106 of the HUD Reform Act, waivers of regulations are granted by the Assistant Secretary with jurisdiction over the regulations for which a waiver was requested. In those cases in which a General Deputy Assistant Secretary granted the waiver, the General Deputy Assistant Secretary was serving in the absence of the Assistant Secretary in accordance with the office's Order of Succession.

This notice covers waivers of regulations granted by HUD from April 1, 2015 through June 30, 2015. For ease of reference, the waivers granted by HUD are listed by HUD program office (for example, the Office of Community Planning and Development, the Office of Fair Housing and Equal Opportunity, the Office of Housing, and the Office of Public and Indian Housing, etc.). Within each program office grouping, the waivers are listed sequentially by the regulatory section of title 24 of the Code of Federal Regulations (CFR) that is being waived. For example, a waiver of a provision in 24 CFR part 58 would be listed before a waiver of a provision in 24 CFR part 570.

Where more than one regulatory provision is involved in the grant of a particular waiver request, the action is listed under the section number of the first regulatory requirement that appears in 24 CFR and that is being waived. For example, a waiver of both § 58.73 and § 58.74 would appear sequentially in the listing under § 58.73.

Waiver of regulations that involve the same initial regulatory citation are in time sequence beginning with the earliest-dated regulatory waiver.

Should HUD receive additional information about waivers granted during the period covered by this report (the second quarter of calendar year 2015) before the next report is published (the third quarter of calendar year 2015), HUD will include any additional waivers granted for the second quarter in the next report.

Accordingly, information about approved waiver requests pertaining to HUD regulations is provided in the Appendix that follows this notice.

Dated: September 14, 2015.

Helen R. Kanovsky,

General Counsel.

Appendix

Listing of Waivers of Regulatory Requirements Granted by Offices of the Department of Housing and Urban Development April 1, 2015 Through June 30, 2015

Note to Reader: More information about the granting of these waivers, including a copy of the waiver request and approval, may be obtained by contacting the person whose name is listed as the contact person directly after each set of regulatory waivers granted.

The regulatory waivers granted appear in the following order:

I. Regulatory waivers granted by the Office of Community Planning and Development.

II. Regulatory waivers granted by the Office of Government National Mortgage Association.

III. Regulatory waivers granted by the Office of Housing.

IV. Regulatory waivers granted by the Office of Public and Indian Housing.

I. Regulatory Waivers Granted by the Office of Community Planning and Development

For further information about the following regulatory waivers, please see the name of the contact person that immediately follows the description of the waiver granted.

• Regulation: 24 CFR 92.214(a)(6).

Project/Activity: Chester County, PA, Department of Community Development requested a waiver of 24 CFR 92.214(a)(6) to invest up to $190,000 of HOME Investment Partnerships (HOME) program funds to purchase a previously assisted 4-unit rental housing project assisted under the HOME program that was in mortgage foreclosure.

Nature of Requirement: The regulation at 24 CFR 92.214(a)(6) prohibits assistance to a project previously assisted with HOME funds during the period of affordability established by the participating jurisdiction in the written agreement under 24 CFR 92.504.

Granted By: Clifford Taffet, General Deputy Assistant Secretary for Community Planning and Development.

Date Granted: April 6, 2015.

Reason Waived: The waiver was granted to permit the County to invest additional HOME funds in the HOME-assisted project during the period of affordability in order to preserve the units as affordable housing. The initial and new investment of HOME funds was within the applicable maximum per-unit subsidy limits, and the HOME period of affordability was extended for an additional ten years.

Contact: Virginia Sardone, Director, Office of Affordable Housing Programs, Office of Community Planning and Development, Department of Housing and Urban Development, 451 Seventh Street SW., Room 7164, Washington, DC 20410, telephone (202) 708–2684.

• Regulation: 24 CFR 570.513(b)(2) and (b)(9).

Project/Activity: The City of Detroit, MI requested a waiver of 24 CFR 570.513(b)(2) and (b)(9) to facilitate the funding of its Home Repair Program, a local housing rehabilitation program. The City planned to fund its program through a lump sum drawdown and arranged for its subrecipient Local Initiative Support Coalition (LISC) to administer the program. LISC arranged for two separate private financial institutions to provide required consideration for the deposit of funds rather than one institution as contemplated by CDBG program regulations. The first institution, Bank of America, agreed to provide LISC with $4 million in funding for the program but declined to be a party to a lump sum drawdown agreement as required under 24

CFR 570.513(b)(2). The second institution, JP Morgan Chase (Chase), agreed to serve as LISC's depository institution, and agreed to be a party to a lump sum agreement and provide the appropriate benefits required under 24 CFR 570.513(b)(9) in support of the program. The City requested a waiver of 24 CFR 570.513(b)(2) and (b)(9) to allow the City to enter into an agreement with LISC and Chase to the extent necessary to allow two separate financial institutions to provide the appropriate benefits in support of the city's local housing rehabilitation program.

Nature of Requirement: The regulation at 24 CFR 570.513(b)(2) requires financial institutions that provide financing for a lump sum fund to execute a written lump sum agreement and specify the obligations and responsibilities of the parties, the terms and conditions on which Community Development Block Grant (CDBG) funds are to be deposited and used or returned, the anticipated level of rehabilitation activities by the financial institution, the rate of interest and other benefits to be provided by the financial institution in return for the lump sum deposit, and such other terms as are necessary for compliance with the provisions of this section. The regulation at 24 CFR 570.513(b)(9) requires the private financial institution in which the funds are deposited to provide other benefits in addition to the payment of interest. These benefits may include the leveraging of the deposited funds, the commitment of private funds at below market interest rates, or the provision of administrative services in support of the rehabilitation program.

Granted By: Harriet Tregoning, Principal Deputy Assistant Secretary for Community Planning and Development.

Date Granted: May 18, 2015.

Reason Waived: Granting the waiver of 24 CFR 570.513(b)(2) and (b)(9) allowed the City of Detroit to enter into an agreement with LISC and Chase to the extent necessary to allow two separate financial institutions to provide the appropriate benefits in support of the city's local housing rehabilitation program. By granting these waivers, the program could be fully implemented bringing needed investment to the City.

Contact: Steve Johnson, Director of Entitlement Communities Division, Office of Community Planning and Development, Department of Housing and Urban Development, 451 Seventh Street SW., Room 7282, Washington, DC 20410, telephone (202) 402–4548.

- Regulation: 24 CFR 570.503(b)(7).

Project/Activity: The County of San Luis Obispo, CA, requested a waiver to allow its subrecipient, the Food Bank Coalition of San Luis Obispo County, to sell a CDBG-funded food bank in Paso Robles and relocate the food bank's operations to a new larger and more efficient facility that will be constructed in part with the proceeds of the sale. The use of the new facility will meet the same national objective as the existing site and will serve a greater number of people in the County.

Nature of Requirement: The regulation at 24 CFR 570.503(b)(7) states that a property acquired by a subrecipient with CDBG funds must be used to meet one of the national objectives in 24 CFR 570.208 until five years after the expiration of the subrecipient agreement. If the property is not used to meet a national objective, the subrecipient must reimburse the county an amount equal to the prorated share of the current fair market value of the property.

Granted By: Harriet Tregoning, Principal Deputy Assistant Secretary for Community Planning and Development.

Date Granted: June 3, 2015.

Reason Waived: This waiver allowed the Food Bank Coalition of San Luis Obispo County to move the food bank from Paso Robles to a new larger and more efficient location that will serve a larger CDBG-eligible population. Rather than reimburse the CDBG program, the Food Bank Coalition will sell the existing Paso Robles site and use the proceeds to help pay for the new facility. A waiver of 24 CFR 570.503(b)(7) was required to allow the Food Bank Coalition to use the proceeds to construct the new facility rather than reimburse the County, and to effect the transfer of programmatic requirements. The CDBG investment and program requirements will be transferred to the new facility and the use of the new facility will meet the same national objective as the use of the existing site.

Contact: Steve Johnson, Director of Entitlement Communities Division, Office of Community Planning and Development, Department of Housing and Urban Development, 451 Seventh Street SW., Room 7282, Washington, DC 20410, telephone (202) 402–4548.

II. Regulatory Waivers Granted by the Office of Government National Mortgage Association (Ginnie Mae)

For further information about the following regulatory waivers, please see the name of the contact person that immediately follows the description of the waiver granted.

- Regulation: 24 CFR 330.20(a)(2)(i)(D).

Project/Activity: Amherst Pierpont Securities LLC (APS) eligibility for approval as a Sponsor of Ginnie Mae guaranteed structured securities.

Nature of Requirement: The regulation at 24 CFR 330.20(a)(2)(i)(D) establishes certain eligibility requirements for an entity applying for approval as a Ginnie Mae Sponsor. An applicant must submit an audited financial statement, which must be issued within the preceding 12 month period that demonstrates compliance with the minimum required amount of shareholders' equity or partners' capital in accordance with Ginnie Mae guidelines.

Granted By: Theodore W. Tozer, President, Ginnie Mae.

Date Granted: June 30, 2015.

Reason Waived: On October 10, 2014 Pierpont Securities LLC (Pierpont Securities) acquired 100% of Amherst ASG Holdings, LLC (Amherst Securities Group) through an exchange of the Parent Company's equity units. Since the acquisition occurred after September 30, 2014, the next audited financial statement will be on the fiscal year that ends later in 2015. The timing of the merger is a special circumstance for APS. Therefore, Ginnie Mae found good cause existed to issue a one-time waiver of the requirement for an applicant for approval as a sponsor to submit an audited financial statement issued within the preceding 12 month period.

Contact: William Hughes, Transaction Management Specialist, Office of Capital Markets, Government National Mortgage Association, Department of Housing and Urban Development, 550 12th Street SW., Suite 300, Washington, DC 20410, telephone (202) 475–4924.

III. Regulatory Waivers Granted by the Office of Housing—Federal Housing Administration (FHA)

For further information about the following regulatory waivers, please see the name of the contact person that immediately follows the description of the waiver granted.

- Regulation: 24 CFR 200.72.

Project/Activity: New York Society for the Relief of the Ruptured and Crippled, Maintaining the Hospital for Special Surgery (HSS) is a not-for-profit, nationally recognized 162-bed academic medical center that specializes in orthopedics and rheumatology and is a member of the New York-Presbyterian Healthcare System and an affiliate of the Weill Medical College of Cornell University. HSS main facilities are located in New York City, New York, with other physician offices, rehabilitation and outpatient centers located in Long Island and Upstate New York, Connecticut, New Jersey, and Florida.

Nature of Requirement: The regulation mandates the project, when completed, shall not violate any material zoning or deed restrictions applicable to the project site, and shall comply with all applicable building and other governmental codes, ordinances, regulations and requirements.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The Hospital does not meet all of the applicable building codes, because it does not have a Permanent Certificate of Occupancy (PCO) for the building, but has a Temporary Certificate of Occupancy. HSS will be able to move to Final Endorsement, enabling the completion of their expansion plan, which includes adding two new inpatient nursing units, expanded pharmacy and pediatric rehabilitation departments and three additional inpatient operating rooms.

Contact: Shelley M. McCracken-Rania, Senior Financial Analyst, Office of Healthcare Programs, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 2247, Washington, DC 20410, telephone 202–402–5366.

- Regulation: 24 CFR 200.926d(f)(1)(i) and (f)(2)(i).

Project/Activity: An extension of the waiver of Minimum Property Standards (MPS) regulations pertaining to water supply systems was requested to permit FHA insurance of mortgages secured by properties located in certain areas of the State of Alaska that rely upon water holding tanks and similar alternative water supply systems.

Nature of Requirement: FHA's MPS regulations governing new construction for single family dwellings provide that to be eligible for FHA insurance, each living unit within newly constructed single family residential property should be capable of delivering a flow of five gallons per minute over a four hour period in order to provide a continuing and sufficient supply of safe water under adequate pressure and appropriate quality for household use. Under these regulatory requirements, water holding tanks, cisterns and similar alternative water supply systems are not considered under FHA requirements as acceptable water supply systems.

Granted By: Edward Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 1, 2015.

Reason Waived: The Santa Ana Homeownership Center requested an additional one year extension of the waiver pending publication of a proposed and final rule on alternative water supply systems.

Contact: Cheryl Walker, Director, Home Valuation Policy Division, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 9274, Washington, DC 20410, telephone (202) 402–6880.

• Regulation: 24 CFR 219.220(b).

Project/Activity: Germano-Millgate Apartments, FHA Project Number 071–44081, Chicago, Illinois. The owners requested deferral of repayment of the Flexible Subsidy Operating Assistance Loan on this project due to their inability to repay the loan in full upon prepayment of the 236 Loan.

Nature of Requirement: The regulation at 24 CFR 219.220(b) governs the repayment of operating assistance provided under the Flexible Subsidy Program for Troubled Projects prior to May 1, 1996 states: ''Assistance that has been paid to a project owner under this subpart must be repaid at the earlier of the expiration of the term of the mortgage, termination of mortgage insurance, prepayment of the mortgage, or a sale of the project . . .'' Either of these actions would typically terminate FHA involvement with the property, and the Flexible Subsidy Loan would be repaid, in whole, at that time.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: June 25, 2015.

Reason Waived: The owner requested and was granted waiver of the requirement to defer repayment of the Flexible Subsidy Operating Assistance Loan to allow the much needed preservation and moderate rehabilitation of the project. The project will be preserved as an affordable housing resource of Chicago, Illinois.

Contact: Minnie Monroe-Baldwin, Branch Chief, Affordable Housing Transaction, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6222, Washington, DC 20410, telephone (202) 402–2636.

• Regulation: 24 CFR 219.220(b).

Project/Activity: J.O. Blanton House, FHA Project Number 083–44025, Louisville, KY. Fifth Street High Rise, Incorporated (owner) seeks approval to defer repayment of the Flexible Subsidy Operating Assistance Loans on the subject project.

Nature of Requirement: The regulation at 24 CFR 219.220(b) (1995), which governs the repayment of operating assistance provided under the Flexible Subsidy Program for Troubled Properties, states ''Assistance that has been paid to a project Owner under this subpart must be repaid at the earlier of the expiration of the term of the mortgage, termination of mortgage insurance, prepayment of the mortgage, or a sale of the project.''

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: June 26, 2015.

Reason Waived: The owner requested and was granted waiver of the requirement to defer repayment of the Flexible Subsidy Operating Assistance Loan. Deferring the loan payment will preserve this affordable housing resource for an additional 35 years through the execution and recordation of a Rental Use Agreement.

Contact: James Wyatt, Account Executive, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6172, Washington, DC 20410, telephone (202) 402–2591.

• Regulation: 24 CFR 232.7.

Project/Activity: Cedar Creek Alzheimer & Dementia Care is a memory care facility. The facility does not meet the requirements of 24 CFR 232.7 pertaining to the configuration of bathrooms in such facilities. The project is located in Los Gatos, CA.

Nature of Requirement: The regulation mandates that, in a board and care home or assisted living facility, not less than one full bathroom must be provided for every four residents, and that the bathroom cannot be accessed from a public corridor or area.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 12, 2015.

Reason Waived: The project is for memory care, all rooms have half-bathrooms and the resident to full bathroom ratio is 9.67: 1.

Contact: Vance T. Morris, Special Assistant, Office of Healthcare Programs, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 2337, Washington, DC 20401, telephone 202–402–2419.

• Regulation: 24 CFR 232.7.

Project/Activity: Oak Creek Alzheimer & Dementia Care is a memory care facility. The facility does not meet the requirements of 24 CFR 232.7 pertaining to the configuration of bathrooms in such facilities. The project is located in Castro Valley, CA.

Nature of Requirement: The regulation mandates that, in a board and care home or assisted living facility, not less than one full bathroom must be provided for every four residents, and that the bathroom cannot be accessed from a public corridor or area.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 12, 2015.

Reason Waived: The project is for memory care, all rooms have half-bathrooms and the resident to full bathroom ratio is 10: 1.

Contact: Vance T. Morris, Special Assistant, Office of Healthcare Programs, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 2337, Washington, DC 20401, telephone 202–402–2419.

• Regulation: 24 CFR 232.7.

Project/Activity: Runk and Pratt is a memory care facility. The facility does not meet the requirements of 24 CFR 232.7 pertaining to the configuration of bathrooms in such facilities. The project is located in Forest, Va.

Nature of Requirement: The regulation mandates that, in a board and care home or assisted living facility, not less than one full bathroom must be provided for every four residents, and that the bathroom cannot be accessed from a public corridor or area.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 12, 2015.

Reason Waived: The project is for memory care, all rooms have half-bathrooms and the resident to full bathroom ratio is 7.28: 1.

Contact: Vance T. Morris, Special Assistant, Office of Healthcare Programs, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 2337, Washington, DC 20401, telephone 202–402–2419.

• Regulation: 24 CFR 232.7.

Project/Activity: Via Christie is a memory care facility. The facility does not meet the requirements of 24 CFR 232.7 pertaining to the configuration of bathrooms in such facilities. The project is located in Omaha, NE.

Nature of Requirement: The regulation mandates that, in a board and care home or assisted living facility, not less than one full bathroom must be provided for every four residents, and that the bathroom cannot be accessed from a public corridor or area.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The project is for memory care, all rooms have half-bathrooms and the resident to full bathroom ratio is 10:1.

Contact: Vance T. Morris, Special Assistant, Office of Healthcare Programs, Office of Housing, Department of Housing and Urban Development, 451 7th Street SW., Room 2337, Washington, DC 20401, (O) 202–402–2419.

• Regulation: 24 CFR 266.200(b)(2).

Project/Activity: Federal Financing Bank (FFB) Risk Sharing Initiative, Substantial Rehabilitation Defined. New York City Housing Development Corporation (NYCHDC).

Nature of Requirement: The regulation at 24 CFR 266.200(b)(2) defines substantial rehabilitation. The following changes to the definition were temporarily made for both Level I and II Housing Finance Agencies: Work that exceeds either: (a) $15,000 times the high cost factor ''as adjusted by HUD for inflation'', or (b) replacement of two or more building systems. 'Replacement' is when cost of replacement work exceeds 50 percent of the cost of replacing the entire system. The base limit is revised to $15,000 per unit for 2015, and will be adjusted annually based on the percentage change published by the Consumer Financial Protection Bureau, or other inflation cost index published by HUD. This change is consistent with proposed changes in the MAP Guide.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The temporary changes were necessary to effectuate the Federal Financing Bank (FFB) Risk Sharing Initiative between Housing and Urban Development and the Treasury Department/FFB announced in Fiscal Year 2014. There are 11 qualified HFAs participants. Concurrent with the rollout of the FFB Initiative, HUD's Office of Multifamily Housing is beginning the process of making regulatory changes to these same provisions. Under this Initiative, FFB provides capital to participating Housing Finance Agencies (HFAs) to make multifamily loans insured under the FHA Multifamily Risk Sharing Program.

Contact: Theodore K. Toon, Director, FHA Multifamily Production, Office of Multifamily Housing Programs, Office of Production, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6134, Washington, DC 20410, telephone (202) 402–8386.

• Regulation: 24 CFR 266.200(c)(2).

Project/Activity: Federal Financing Bank (FFB) Risk Sharing Initiative, Equity Take-Outs. New York City Housing Development Corporation (NYCHDC).

Nature of Requirement: HUD's regulation at 266.200(c)(2) addresses equity take-outs for existing projects (refinance transactions), and permit the insured mortgage to exceed the sum of the total cost of acquisition, cost of financing, cost of repairs, and reasonable transaction costs or ''equity take-outs'' in refinances of HFA-financed projects and those outside of HFA's portfolio if the result is preservation with the following conditions:

1. Occupancy is no less than 93 percent for previous 12 months;

2. No defaults in the last 12 months of the HFA loan to be refinanced;

3. A 20-year affordable housing deed restriction placed on title that conforms to the section 542(c) statutory definition;

4. A Property Capital Needs Assessment (PCNA) must be performed and funds escrowed for all necessary repairs, and reserves funded for future capital needs; and

5. For projects subsidized by Section 8 Housing Assistance Payment (HAP) contracts: Owner agrees to renew HAP contract(s) for 20 year term, (subject to appropriations and statutory authorization, etc.), and existing and post-refinance HAP residual receipts are set aside to be used to reduce future HAP payments.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The waiver was necessary to effectuate the Federal Financing Bank (FFB) Risk Sharing Initiative between Housing and Urban Development and the Treasury Department/FFB announced in Fiscal Year 2014. There are 11 qualified HFAs participants. Concurrent with the rollout of the FFB Initiative, HUD's Office of Multifamily Housing is beginning the process of making regulatory changes to these same provisions. Under this Initiative, FFB provides capital to participating Housing Finance Agencies (HFAs) to make multifamily loans insured under the FHA Multifamily Risk Sharing Program.

Contact: Theodore K. Toon, Director, FHA Multifamily Production, Office of Multifamily Housing Programs, Office of Production, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6134, Washington, DC 20410, telephone (202) 402–8386.

• Regulation: 24 CFR 266.200(d).

Project/Activity: Federal Financing Bank (FFB) Risk Sharing Initiative, Underwriting of Projects with Section 8 HAP Contracts. New York City Housing Development Corporation (NYCHDC).

Nature of Requirement: HUD's regulation at 24 CFR 266.200(d) pertains to projects with Section 8 rental subsidies or other rental subsidies: For refinancing of Section 202 projects, and for Public Housing Agency (PHA) projects converting to Section 8 through RAD, HUD will permit NYCHDC to underwrite the financing using current or to be adjusted project-based Section 8 assisted rents, even though they exceed the market rates. This is consistent with HUD Housing Notice 04–21, ''Amendments to Notice 02–16: Underwriting Guidelines for Refinancing of Section 202, and Section 202/8 Direct Loan Repayments'', which grants authority only to those lenders refinancing with mortgage programs under the National Housing Act.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The waiver was necessary to effectuate the Federal Financing Bank (FFB) Risk Sharing Initiative between Housing and Urban Development and the Treasury Department/FFB announced in Fiscal Year 2014. The waiver is consistent with changes that HUD's Office of Multifamily Housing is seeking now to the regulation and as previously approved in March 2015 for the first 11 HFAs participating in the Initiative. Under this Initiative, FFB provides capital to participating Housing Finance Agencies (HFAs) to make multifamily loans insured under the FHA Multifamily Risk Sharing Program.

Contact: Theodore K. Toon, Director, FHA Multifamily Production, Office of Multifamily Housing Programs, Office of Production, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6134, Washington, DC 20410, telephone (202) 402–8386.

• Regulation: 24 CFR 266.410(e).

Project/Activity: Minnesota Housing Finance Agency, for Crystal Lake Townhomes, Grand Rapids, Minnesota.

Nature of Requirement: The regulation at 24 CFR 266.410(e) pertaining to amortization states that the mortgage must provide for complete amortization (*i.e.,* regularly amortizing) over the term of the mortgage. This is financing under the Risk Sharing Program.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 5, 2015.

Reason Waived: The granting of this waiver promotes preservation and affordability with minimal increased risk to the FHA Insurance Fund. Minnesota's HFA project is a 48-unit property located in the city of Grand Rapids. The approval, however, is subject to the following conditions: (1) Minnesota Housing Finance Agency (MN Housing) will assume 50 percent of the risk, and (2) annual property inspections will be performed with appropriate adjustments made to the replacement reserves as needed to ensure the Project is maintained in good physical condition. Minnesota will finance Crystal Lake Townhomes (Project) with a mortgage that will mature in November, 2041 with a small balloon payment of preservation property receiving the benefit of a Section 8 subsidy for all units.

Contact: Theodore K. Toon, Director, FHA Multifamily Production, Office of Multifamily Housing Programs, Office of Production, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6134, Washington, DC 20410, telephone (202) 402–8386.

• Regulation: 24 CFR 266.620(e).

Project/Activity: Federal Financing Bank (FFB) Risk Sharing Initiative, Termination of Mortgage Insurance. New York City Housing Development Corporation (NYCHDC). Waivers of these 4 sections of the regulation were approved in March, 2015 for the first 11 HFAs approved to participate in the Initiative.

Nature of Requirement: The regulation at 24 CFR 266.620(e), pertains to termination of mortgage insurance provision (required for FFB Initiative). As required by the Initiative, New York City Housing Development Corporation (NYCHDC) agrees to indemnify HUD for all amounts paid to FFB if ''the HFA or its successors commit fraud, or make a material misrepresentation to the Commissioner with respect to information culminating in the Contract of Insurance on the mortgage, or while the Contract of Insurance is in existence''. Only Level I HFAs are eligible for FFB financing, thereby ensuring the HFA maintains financial capacity to perform under the indemnification agreement. If the HFA loses its ''A'' rating, HFA must post the required reserve account as outlined in 24 CFR part 266.

Granted By: Edward L. Golding, Principal Deputy Assistant Secretary for Housing.

Date Granted: May 18, 2015.

Reason Waived: The waiver was necessary to effectuate the Federal Financing Bank (FFB) Risk Sharing Initiative between Housing and Urban Development and the Treasury Department/FFB announced in Fiscal Year 2014. There are 11 qualified HFAs participants. Concurrent with the rollout of the FFB Initiative, HUD's Office of Multifamily is beginning the process of making regulatory changes to these same provisions. Under this Initiative, FFB provides capital to participating Housing Finance Agencies (HFAs) to make multifamily loans insured under the FHA Multifamily Risk Sharing Program.

Contact: Theodore K. Toon, Director, FHA Multifamily Production, Office of Multifamily Housing Programs, Office of Production, Office of Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 6134, Washington, DC 20410, telephone (202) 402–8386.

IV. Regulatory Waivers Granted by the Office of Public and Indian Housing

For further information about the following regulatory waivers, please see the name of the contact person that immediately follows the description of the waiver granted.

• Regulation: 24 CFR 5.801(d)(1), 24 CFR 902.33(c) and 902.62(a)(3).

Project/Activity: Colorado Division of Housing (CO911) Denver, CO.

Nature of Requirement: These regulations establish certain reporting compliance dates. The audited financial statements are required to be submitted to the Real Estate Assessment Center (REAC) no later than nine months after the housing authority's (HA) fiscal year end (FYE), in accordance with the Single Audit Act and OMB Circular A–133.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 29, 2015.

Reason Waived: The Housing Authority (Section 8-only entity) requested a waiver to obtain additional time to allow for input of its FYE June 30, 2014 audited financial data into the FASS online system. The State's single audited financial information had recently been submitted.

Contact: Scott Sherman, Acting Program Manager, NASS, Real Estate Assessment Center, Office of Public and Indian Housing, Department of Housing and Urban Development, 550 12th Street SW., Suite 100, Washington, DC 20410, telephone (202) 475–7975.

• Regulation: 24 CFR 5.801(d)(1), 24 CFR 902.33(c) and 902.62(a)(3).

Project/Activity: Center Housing Authority (CO043) Center, CO.

Nature of Requirement: These regulations establish certain reporting compliance dates. The audited financial statements are required to be submitted to the Real Estate Assessment Center (REAC) no later than nine months after the housing authority's (HA) fiscal year end (FYE), in accordance with the Single Audit Act and OMB Circular A–133.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 29, 2015.

Reason Waived: The Housing Authority requested a waiver to obtain additional time to allow for input of its FYE June 30, 2014 audited financial data into the FASS online system, and to remove the LPF score of zero as it pertains to the Public Housing Assessment System (PHAS). The HAs auditor was involved in an auto accident. The audited data was subsequently submitted on April 1, 2015 (one-day late).

Contact: Scott Sherman, Acting Program Manager, NASS, Real Estate Assessment Center, Office of Public and Indian Housing, Department of Housing and Urban Development, 550 12th Street SW., Suite 100, Washington, DC 20410, telephone (202) 475–7975.

• Regulation: 24 CFR 5.801(d)(1).

Project/Activity: Easton Housing Authority (MD019) Easton, MD.

Nature of Requirement: The regulation establishes certain reporting compliance dates. The audited financial statements are required to be submitted to the Real Estate Assessment Center (REAC) no later than nine months after the housing authority's (HA) fiscal year end (FYE), in accordance with the Single Audit Act and OMB Circular A–133.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 13, 2015.

Reason Waived: The HA requested a waiver to obtain an extension (until May 15, 2015) to submit its audited financial data for FYE June 30, 2014. The HA indicated that additional time is necessary due to extensive damages incurred to its Administrative office resulting in ruptured pipelines that destroyed computers and files.

Contact: Scott Sherman, Acting Program Manager, NASS, Real Estate Assessment Center, Office of Public and Indian Housing, Department of Housing and Urban Development, 550 12th Street SW., Suite 100, Washington, DC 20410, telephone (202) 475–7975.

• Regulation: 24 CFR 5.801(d)(1).

Project/Activity: Tallahassee Housing Authority (FL073), Tallahassee, FL.

Nature of Requirement: The regulation establishes certain reporting compliance dates. The audited financial statements are required to be submitted to the Real Estate Assessment Center (REAC) no later than nine months after the housing authority's (HA) fiscal year end (FYE), in accordance with the Single Audit Act and OMB Circular A–133.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 6, 2015.

Reason Waived: The Housing Authority (HA) requested a waiver of 24 CFR 5.110 to obtain a 60-day extension (until May 30, 2015) to submit its audited financial data for fiscal year end (FYE) June 30, 2014. The HA experienced numerous ledger balances and accounting errors due to fraud, having difficulty procuring a qualified Finance Director, and had recently converted to a new software system.

Contact: Judy Wojciechowski, Program Manager, NASS, Real Estate Assessment Center, Office of Public and Indian Housing, Department of Housing and Urban Development, 550 12th Street SW., Suite 100, Washington, DC 20410, telephone (202) 475–7907.

• Regulation: 24 CFR 982.516(a)(2)(ii).

Project/Activity: Raleigh County Housing Authority (RCHA), Raleigh, NC.

Nature of Requirement: The regulation at 24 CFR 982.516(a)(2)(ii) states that the public housing agency must obtain and document in the tenant file third-party verification of the value of assets or must document in the tenant file why third-party verification was not available.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 13, 2015.

Reason Waived: The majority of participants have less than $5,000 in asset income; (2) the cost of obtaining third-party documentation is borne by participants; and (3) waiting for such documentation frequently delays the completion of interim and annual reexaminations. A proposed regulation issued by the Department and published in the **Federal Register** on January 6, 2015 *(Streamlining Administrative Regulations for Public Housing, Housing Choice Voucher, Multifamily Housing, and Community Planning and Development Programs)* would likewise authorize self-certification of assets of $5,000 or less.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.503(a)(3) and 982.503(c)(2).

Project/Activity: Housing Authority of the County of Alameda (HACA), Hayward, CA.

Nature of Requirement: The regulation at 24 CFR 982.503(a)(3) states that a PHA's voucher payment standard schedule shall establish a single payment standard amount for each unit size. The regulation at 24 CFR 982.503(c)(2) states that the HUD Field Office may approve an exception payment standard amount from above 110 percent of the published fair market rents (FMR) if the HUD Field Office determines that approval is justified by either the median rent method or the 40th or 50th percentile rent method and that such approval is also supported by an appropriate program justification.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 5, 2015.

Reason Waived: These regulations were waived to allow HACA to establish payment standards at 120 percent of the FMR for all bedroom sizes in all areas of the county for its HUD-Veterans Affairs Supportive Housing (VASH) program. These families generally have a more difficult time finding units before their vouchers expire and require 40 percent more voucher extensions than non-HUD–VASH families in a low vacancy area.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Colorado Department of Local Affairs (CDLA), Denver, CO.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 15, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the participant's current unit that meets the participant's needs To provide this reasonable accommodation so that the participant could remain in the participant's current unit and pay no more than 40 percent of adjusted income toward the family share, the CDLA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Housing Authority of the County of Alameda (HACA), Hayward, CA.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 16, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the participant's current unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in the participant's current unit and pay no more than 40 percent of adjusted income toward the family share, HACA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Housing Authority of the County of Alameda (HACA), Hayward, CA.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 16, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the participant's current new unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in participant's unit and pay no more than 40 percent of adjusted income toward the family share, the HACA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: San Francisco Housing Authority (SFHA), San Francisco, CA.

Nature of Requirement: 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 7, 2015.

Reason Waived: The two HUD-VASH participants, who are persons with disabilities, each required an exception payment standard to move to accessible units that met their needs. To provide this reasonable accommodation so that the participants could move to these units and pay no more than 40 percent of their adjusted income toward the family share, the SFHA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Boston Housing Authority (BHA), Boston, MA.

Nature of Requirement: The regulation 24 CFR 982.505(d) states that a public housing agency may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 3, 2015.

Reason Waived: The client, whose child is a person with disabilities, required an exception payment standard so that the child could remain in the unit without being rent burdened. To provide this reasonable accommodation so that the client and child could remain in their current unit and pay no more than 40 percent of adjusted income toward the family share, BHA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Housing Authority of the County of Alameda (HACA), Hayward, CA.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 8, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the participant's current unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in the participant's current unit and pay no more than 40 percent of adjusted income toward the family share, the HACA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: City of Chandler Housing and Redevelopment Division (CCHRD), Chandler, AZ.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 9, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the participant's current unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in this unit and pay no more than 40 percent of adjusted income toward the family share, the CCHRD was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: San Francisco Housing Authority (SFHA), San Francisco, CA.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 9, 2015.

Reason Waived: A HUD–VASH applicant, who is a person with disabilities, required an exception payment standard to move to accessible unit that met the person's needs. To provide this reasonable accommodation so that the applicant could move to this unit and pay no more than 40 percent of adjusted income toward the family share, the SFHA was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: City of Des Moines Housing Services Department (CDMHS), Des Moines, IA.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 15, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the current unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in this unit and pay no more than 40 percent of adjusted income toward the family share, the CCHRD was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 982.505(d).

Project/Activity: Washington County Department of Housing Services (WCDHS), Hillsboro, OR.

Nature of Requirement: The regulation at 24 CFR 982.505(d) states that a PHA may only approve a higher payment standard for a family as a reasonable accommodation if the higher payment standard is within the basic range of 90 to 110 percent of the fair market rent (FMR) for the unit size.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: June 23, 2015.

Reason Waived: The participant, who is a person with disabilities, required an exception payment standard to remain in the current unit that meets the participant's needs. To provide this reasonable accommodation so that the participant could remain in this unit and pay no more than 40 percent of adjusted income toward the family share, the WCDHS was allowed to approve an exception payment standard that exceeded the basic range of 90 to 110 percent of the FMR.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 985.101(a).

Project/Activity: Housing Authority of Gloucester County (HAGC), Deptford, NJ.

Nature of Requirement: The regulation at 24 CFR 985.101(a) states a PHA must submit the HUD-required Section Eight Management Assessment Program (SEMAP) certification form within 60 calendar days after the end of its fiscal year.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 17, 2015.

Reason Waived: This waiver was granted because for the HAGC's fiscal year ending December 31, 2014. The HAGC experienced an emergency in its public housing units and due to the time and effort to rehouse the affected families, the HAGC was unable to submit its SEMAP certification on or before March 1, 2015.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 985.101(a).

Project/Activity: Housing Authority of the Borough of Glassboro (HABG), Deptford, NJ.

Nature of Requirement: The regulation at 24 CFR 985.101(a) states a PHA must submit the HUD-required Section Eight Management Assessment Program (SEMAP) certification form within 60 calendar days after the end of its fiscal year.

Granted By: Lourdes Castro Ramírez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 21, 2015.

Reason Waived: This waiver was granted because for the HABG's fiscal year ending December 31, 2014. The Housing Authority of Gloucester County (HAGC) submits the SEMAP certification for HABG. HAGC experienced an emergency in its public housing units and due to the time and effort to rehouse the affected families, the HAGC was unable to submit the SEMAP certification for HABG on or before March 1, 2015.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4216, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 985.101(a).

Project/Activity: Bath Township Housing Commission (BTHC), Bath, MI.

Nature of Requirement: The regulation at 24 CFR 985.101(a) states a PHA must submit the HUD-required Section Eight Management Assessment Program (SEMAP) certification form within 60 calendar days after the end of its fiscal year.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: April 21, 2015.

Reason Waived: BTHC provided documentation that, on February 18, 2015, it sent an email to REAC_TAC to report that it was unable to enter the fair market rents and payment standards of its SEMAP certification into the SEMAP module of IMS/PIC. It was also documented that REAC_TAC did not respond to BTHC until after the deadline noted above. The date of the email was March 9, 2015.

Contact: Becky Primeaux, Director, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4210, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 985.101(a).

Project/Activity: City of Balch Springs (CBS), Balch Springs, TX.

Nature of Requirement: The regulation at 24 CFR 985.101(a) states a PHA must submit the HUD-required Section Eight Management Assessment Program (SEMAP) certification form within 60 calendar days after the end of its fiscal year.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 29, 2015.

Reason Waived: The executive director was out of the office the week of Thanksgiving from November 24 through November 27, 2014. The SEMAP certification was due on November 29, 2014. The SEMAP coordinator was out of the office due to a family emergency at the same time and there was no time to prepare and submit the SEMAP certification by the deadline.

Contact: Becky Primeaux, Director, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4210, Washington, DC 20410, telephone (202) 708–0477.

• Regulation: 24 CFR 983.51(b).

Project/Activity: Pasco County Housing Authority (PCHA), Dade City, FL.

Nature of Requirement: The regulation at 24 CFR 983.51(b) states that PHA must select project-based voucher (PBV) proposals in accordance with the selection procedures in the PHA's administrative plan by either a request for proposals or, alternatively, a selection of a proposal for housing assisted under a federal, state or local government housing assistance, community development or supportive services program that required a competitive selection of proposals.

Granted By: Lourdes Castro Ramirez, Principal Deputy Assistant Secretary for Public and Indian Housing.

Date Granted: May 18, 2015.

Reason Waived: HUD's Office of Public Housing Investments reported that PCHA, in partnership with Pasco County, applied for and received a HUD FY 2012 Choice Neighborhoods Planning Grant for the Lacoochee/Trilby area of Pasco County. PCHA owns two USDA Farmers Home developments, Cypress Manor (24 units) and Cypress Farms (102 units). The public housing units at Cypress Villas I (27 units) and Cypress Villas II (12 units) and the USDA units are contiguous with a similar look and need for improved conditions at the sites. However, the USDA units are no longer eligible for additional loans. By attaching PBV units to 25 USDA units (the maximum allowed under 24 CFR 983.56) at Cypress Farms, debt for the USDA units could be leveraged and improvements made.

Contact: Becky Primeaux, Housing Voucher Management and Operations Division, Office of Public Housing and Voucher Programs, Office of Public and Indian Housing, Department of Housing and Urban Development, 451 Seventh Street SW., Room 4210, Washington, DC 20410, telephone (202) 708–0477.

[FR Doc. 2015–23486 Filed 9–17–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

[Docket No. FR–5841–N–03]

Notice of Proposed Information Collection: Comment Request; HUD Standard Grant Application Forms: Detailed Budget Form (HUD–424–CB), Budget Worksheet (HUD–424CBW), Application for Federal Assistance (SF–424), and the Third-Party Documentation Facsimile Transmittal Form (HUD–96011)

AGENCY: Office of the Chief Information Officer, HUD.

ACTION: Notice.

SUMMARY: The proposed information collection requirement described below will be submitted to the Office of Management and Budget (OMB) for review, as required by the Paperwork Reduction Act. The Department is soliciting public comments on the subject proposal.

DATES: November 17, 2015.

ADDRESSES: Interested persons are invited to submit comments regarding this proposal. Comments should refer to the proposal by name and/or OMB approval numbers (2535–0017), (2525–0018), (4040–0004) and should be sent to: Colette Pollard, Departmental Reports Management Officer, QDAM, Department of Housing and Urban Development, 451 Seventh Street SW., Washington, DC 20410; Telephone (202) 402–4300, (this is not a toll-free number) or email Ms. Pollard at *Colette.Pollard@hud.gov;* for a copy of the proposed form and other available information.

FOR FURTHER INFORMATION CONTACT: Dorthera Yorkshire, AJT, Grants Management and Oversight Division, Department of Housing and Urban Development, 451 Seventh Street SW., Room 3156, Washington, DC 20410; email: *Dorthera.Yorkshire@hud.gov;* telephone (202) 402–4336; Fax (202) 708–0531 (this is not a toll-free number) for other available information. If you are a hearing-or-speech-impaired person, you may reach the above telephone numbers through TTY by calling the toll-free Federal Information Relay Service at 1–800–877–8339.

SUPPLEMENTARY INFORMATION: The Department will submit the proposed information collection to OMB for review, as required by the Paperwork Reduction Act of 1995 (44 U.S.C. Chapter 35, as amended).

This Notice is soliciting comments from members of the public and affecting agencies concerning the proposed collection of information 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; (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 collection techniques or other forms of information technology, *e.g.*, permitting electronic submission of responses.

This Notice lists the following information:

Grant Application Detailed Budget Form (HUD–424–CB)
Grant Application Detailed Budget Worksheet (HUD–424–CBW)
OMB Control Number: 2501–0017
Facsimile Transmittal Form (HUD–96011)
OMB Control Number: 2535–0118
Application for Federal Assistance (SF–424)
OMB Control Number: 4040–0004

Description of the need for the information and proposed use: HUD-Common Budget Form and Worksheet intended to offer consolidated and streamlined grant application processes in accordance with the provisions of Public Law 106–107, The Federal Financial Assistance Improvement Act of 1999.

Agency form numbers, if applicable: HUD–424CB and HUD–424CBW.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: An estimation of the total number of hours needed to prepare the forms for each grant application is one (1) hour, however, the burden will be assessed against each individual grant program submission under the Paperwork Reduction Act; number of respondents is 9,091; frequency of response is on the occasion of application for benefits.

Status of the proposed information collection: Extension of currently approved collection.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Description of the need for the information and proposed use: The use of the Third-Party Documentation Facsimile Transmittal Form allows the Department to collect the same information electronically as we would for a paper-based application. It also produces an electronic version of the document that will be matched with the electronic application submitted through grants.gov to HUD.

Agency form numbers, if applicable: Third-Party Documentation Facsimile Transmittal Form (HUD–96011).

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response: An estimation of the total number of hours needed to prepare the forms for each grant application is 5 minutes per response, however, the burden will be assessed against each individual grant program submission under the Paperwork Reduction Act; number of respondents is 33,000 frequency of response is on the occasion of application for benefits.

Status of the proposed information collection: Extension of currently approved collection.

Authority: Section 3506 of the Paperwork Reduction Act of 1995, 44 U.S.C. Chapter 35, as amended.

Description of the need for the information and proposed use: This is a standard form required for use as a cover sheet for submission of pre-applications and applications and related information under discretionary programs. Some of the items are required and some are optional at the discretion of the applicant or the federal agency (agency). Required fields on the form are identified with an asterisk (*) and are also specified as ''Required'' in the instructions below. In addition to these instructions, applicants must consult agency instructions to determine other specific requirements.

Agency form numbers, if applicable: SF–424 Application for Federal Assistance.

Estimation of the total number of hours needed to prepare the information collection including number of respondents, frequency of response, and hours of response. An estimation of the total number of hours needed to prepare the forms for each grant application is estimated to average 30 minutes per response however, the burden will be assessed against each individual grant program submission under the Paperwork Reduction Act; number of respondents is 33,000 frequency of response is on the occasion of application for benefits.

Status of the proposed information collection: Extension of currently approved collection.

Authority: PL: Pub. L. 106–107 468 Name of Law: Federal Financial Assistance Management Improvement Act of 1999. PL: Pub. L. 109–282 2590 Name of Law: Federal Funding Accountability and Transparency Act of 2006.

Dated: September 14, 2015.

Julie D. Hopkins,

Grants Management and Oversight, Director, Office of Strategic Planning and Management.

[FR Doc. 2015–23463 Filed 9–17–15; 8:45 am]

BILLING CODE 4210–67–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[LLCOF02000 L14400000.ER0000; COC–49757]

Notice of Realty Action; Recreation and Public Purposes Act Classification for Lease in Chaffee County, Colorado

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of realty action.

SUMMARY: The Bureau of Land Management (BLM) has examined and found suitable for classification for lease under the Recreation and Public Purposes (R&PP) Act, as amended (43 U.S.C. 860 *et seq.*), approximately 19.34 acres of public land in Chaffee County, Colorado. The BLM proposes to amend the Colorado Parks and Wildlife's (CPW) existing R&PP Lease (COC–49757) to include the following 19.34 acres in the BLM Salida East Recreation area. The BLM and CPW jointly manage a number of recreation sites in the Arkansas River corridor under a cooperative management agreement. Public lands jointly managed by the BLM and CPW are designated as the Arkansas Headwaters Recreation Area (AHRA). The lands requested in the CPW's lease amendment application are located on public lands within the river corridor and are currently managed by the BLM as a developed recreational facility. If the lease is approved the lands will become part of the AHRA. An R&PP lease to CPW will allow improvements in the Salida East facilities and enhance opportunities for public recreation and public safety.

DATES: Interested parties may submit written comments regarding the proposed classification of lands, or lease of the land, on or before November 2, 2015.

ADDRESSES: Written comments concerning this notice should be addressed to: Bureau of Land Management, Royal Gorge Field Office, 3028 East Main St., Cañon City, CO 81212.

FOR FURTHER INFORMATION CONTACT: Jeff Brown, Realty Specialist, BLM Front Range District Office, by phone (719) 852–6260, or by email at *j75brown@blm.gov.* Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact the above individual during normal business hours. The FIRS is available 24 hours a day, 7 days a week, to leave a message or question with the above individual. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION: The following public land in Chaffee County, Colorado, has been examined and found suitable for classification, for lease, to CPW under the provisions of the R&PP Act, as amended (43 U.S.C 869 *et seq.*):

A certain parcel of land, located entirely within government lots 17, 18 and 19, sec. 10, T. 49 N., R. 9 E., N.M.P.M., as surveyed in the official plat of record, accepted December 22, 1999, *T. 49 N., R. 9 E., NMPM, Sec. 10,* described as follows:

Beginning at corner no. 1 of Tract 37, as surveyed in the official plat of record, accepted December 22, 1999; thence northerly along the western boundary of government lot 17 to the intersection of the centerline of the Arkansas River; thence southeasterly along the centerline of the Arkansas River to the intersection of the southerly boundary of sec. 10; thence westerly, along the southern boundary of sec. 10 to the intersection with the northerly Right-of-Way for U.S. Highway 50, as described in the BLM Right-of-Way Grant No. COD–0–054071; thence northwesterly along said U.S. Highway 50 Right-of-Way to a point at the intersection of the projected 3–4 line of said Tract 37 and the said U.S. Highway Right-of-Way; thence northeasterly to corner no. 3 of said Tract 37; thence along the 3–4 line of said Tract 37 to corner no. 4 of said Tract 37; thence along the 4–5 line of said Tract 37 to corner no. 5 of said Tract 37; thence along the 5–6 line of said Tract 37 to corner no. 6 of said Tract 37; thence along the 6–1 line of said Tract 37 to corner no. 1 of said Tract 37, the point of beginning.

Excluding any portions of any valid and existing mining claims located within the above described parcel at the time of the publication of this notice.

The above described parcel of land contains 19.34 ac. more or less, as determined through official records.

The land is not needed for any Federal purpose other than for current and proposed recreational purposes. The lease is consistent with current bureau land use planning and would be in the public interest.

Detailed information concerning this proposed project, including, but not limited to documentation relating to compliance with applicable environmental and cultural resource laws, is available for review at the BLM Royal Gorge Field Office at the address above.

Upon publication of this notice in the **Federal Register**, the lands described above will be segregated from all forms of appropriation under the public lands laws, including the general mining laws, except for lease under the R&PP Act; leasing under the mineral leasing laws; and disposal under the mineral material disposal laws.

Classification Comments: Interested parties may submit comments involving the suitability of the land for joint management by the BLM and CPW with the additional improvements and upgrades proposed by CPW. Comments on the classification are restricted to whether the land is physically suited for the proposal, whether the use will maximize the future use or uses of the land, whether the use is consistent with local planning and zoning, or if the use is consistent with State and Federal programs.

Application Comments: Interested parties may submit comments regarding the specific use proposed in the application and plan of development that would amend R&PP lease COC-49757 and whether the BLM followed proper administrative procedures in reaching the decision to lease under the R&PP Act.

Any comments will be reviewed by the BLM who may sustain, vacate, or modify this realty action. In the absence of any adverse comments, the classification of the land described in this notice will become effective November 17, 2015.

Before including your 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.

Authority: 43 CFR 2741.5.

Ruth Welch,

BLM Colorado State Director.

[FR Doc. 2015–23483 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–JB–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[F–14851–B2, F–14874–B2; LLAK940000–L14100000–HY0000–P]

Alaska Native Claims Selection

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of decision approving lands for conveyance.

SUMMARY: Notice is hereby given that an appealable decision will be issued by the Bureau of Land Management (BLM), approving conveyance of the surface estate in the lands described below to NANA Regional Corporation, Inc., Successor in Interest to Deering Ipnatchiak Corporation, and Katyaak Corporation, pursuant to the Alaska Native Claims Settlement Act (ANCSA). The subsurface estate in these lands will be conveyed to NANA Regional Corporation, Inc., when the surface estate is conveyed to NANA Regional Corporation, Inc., as Successor in Interest to Deering Ipnatchiak Corporation, and Katyaak Corporation.

DATES: Any party claiming a property interest in the lands affected by the decision may appeal the decision in accordance with the requirements of 43 CFR part 4. Please see the **SUPPLEMENTARY INFORMATION** section for the time limits for appealing the decision.

ADDRESSES: A copy of the decision may be obtained from: Bureau of Land Management, Alaska State Office, 222 West Seventh Avenue, #13, Anchorage, AK 99513–7504.

FOR FURTHER INFORMATION CONTACT: The BLM by phone at 907–271–5960 or by email at *blm_ak_akso_public_room@blm.gov.* Persons who use a Telecommunications Device for the Deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1 800–877–8339 to contact the BLM during normal business hours. In addition, the FIRS is available 24 hours a day, 7 days a week, to leave a message or question with the BLM. The BLM will reply during normal business hours.

SUPPLEMENTARY INFORMATION: As required by 43 CFR 2650.7(d), notice is hereby given that an appealable decision will be issued by the BLM to NANA Regional Corporation, Inc., Successor in Interest to Deering Ipnatchiak Corporation, and Katyaak Corporation. The decision approves the surface estate in the lands described below for conveyance pursuant to the Alaska Native Claims Settlement Act (43 U.S.C. 1601, *et. seq.*). The subsurface estate in these lands will be conveyed to NANA Regional Corporation, Inc., when the surface estate is conveyed to NANA Regional Corporation, Inc., Successor in Interest to Deering Ipnatchiak Corporation, and Katyaak Corporation. Deering Ipnatchiak Corporation, and Katyaak Corporation were the original ANCSA corporations for the villages of Deering and Kiana, and merged with NANA Regional Corporation, Inc. in 1976 under the authority of Public Law 94–204.

The lands are located in the vicinity of Deering and Kiana, Alaska and are described as:

Kateel River Meridian, Alaska

T. 18 N., R. 9 W.,
Sec. 21.
Containing 640 acres.
T. 6 N., R. 17 W.,
Secs. 1 to 36, inclusive.
Containing 22,923.84 acres.
T. 7 N., R. 18 W.,
Secs. 16 to 36, inclusive.
Containing 13,319.47 acres.
Aggregating 36,883.31 acres.

Notice of the decision will also be published once a week for four consecutive weeks in the *Arctic Sounder.*

Any party claiming a property interest in the lands affected by the decision may appeal the decision in accordance with the requirements of 43 CFR part 4 within the following time limits:

1. Unknown parties, parties unable to be located after reasonable efforts have been expended to locate, parties who fail or refuse to sign their return receipt, and parties who receive a copy of the decision by regular mail which is not certified, return receipt requested, shall have until October 19, 2015 to file an appeal.

2. Parties receiving service of the decision by certified mail shall have 30 days from the date of receipt to file an appeal.

Parties who do not file an appeal in accordance with the requirements of 43 CFR part 4 shall be deemed to have waived their rights. Notices of appeal transmitted by electronic means, such as facsimile or email, will not be accepted as timely filed.

Ralph L. Eluska, Sr.,

Land Transfer Resolution Specialist, Division of Lands and Cadastral.

[FR Doc. 2015–23480 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–JA–P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

DEPARTMENT OF AGRICULTURE

Forest Service

[15XL LLIDI02000 L71220000.EO0000–LVTFDX508400 241A 4500080287]

Notice of Availability of Draft Environmental Impact Statement for the Proposed Rasmussen Valley Mine, Caribou County, Idaho

AGENCY: Bureau of Land Management, Interior; United States Forest Service, USDA.

ACTION: Notice of availability.

SUMMARY: In accordance with the National Environmental Policy Act of 1969, as amended (NEPA), the Bureau of Land Management (BLM) and the U.S. Department of Agriculture, Forest Service (USFS), Caribou-Targhee National Forest (CTNF), have prepared a Draft Environmental Impact Statement (EIS) for the proposed Rasmussen Valley Mine, and by this Notice are announcing the opening of the comment period.

DATES: To ensure comments will be considered, the Agencies must receive written comments on the Rasmussen Valley Mine Draft EIS within 45 days following the date the Environmental Protection Agency publishes their Notice of Availability in the **Federal Register**. The BLM will announce any future public meetings and any other public involvement activities at least 15 days in advance through public notices, media news releases, or mailings.

ADDRESSES: You may submit comments by any of the following methods:

- *Email: blm_id_rasmussenvalleyeis@blm.gov.*
- *Fax:* 303–471–3472.
- *Mail:* Rasmussen Valley Mine EIS, ARCADIS U.S., Inc., 630 Plaza Drive, Suite 100, Highlands Ranch, CO 80129.

Please reference ''Rasmussen Valley Mine EIS'' on all correspondence. CD–ROM and print copies of the Rasmussen Valley Mine Draft EIS are available in the BLM Pocatello Field Office at the following address: 4350 Cliffs Drive, Pocatello, ID 83204. In addition, an electronic copy of the Draft EIS is available at either of the Web addresses listed below:

- *BLM Land Use Planning and NEPA Register: http://on.doi.gov/1GpGxyW.*
- *Caribou-Targhee National Forest Current and Recent Projects: http://www.fs.usda.gov/projects/ctnf/landmanagement/projects.*

FOR FURTHER INFORMATION CONTACT: William (Bill) Volk, Bureau of Land Management, Pocatello Field Office, telephone 208–236–7503; address at 4350 Cliffs Drive, Pocatello, ID 83204; email at *wvolk@blm.gov.* Persons who use a telecommunications device for the deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact the above individual during normal business hours. The FIRS is available 24 hours a day, 7 days a week, to leave a message or question for the above individual. You will receive a reply during normal business hours.

SUPPLEMENTARY INFORMATION: Nu-West Industries, Inc., doing business as Agrium Conda Phosphate Operations (Agrium), has submitted a mine plan for the Rasmussen Valley Mine to exercise their existing contractual rights to recover phosphate ore reserves contained within Federal Phosphate Lease I–05975 (the Lease). They have also filed an application to modify this lease by increasing its size by 170 acres. The Proposed Action would include 440.4 acres of new disturbance and develop a new open pit phosphate mining operation on the Lease that would include mining the pit in panels, backfilling depleted panels with overburden, storing overburden in piles external to the pit, construction of a haul road, development of a water management plan, and construction of other ancillary facilities. Ore would be processed off site at Agrium's Conda Phosphate Operations (CPO) Fertilizer Manufacturing Plant northeast of Soda Springs. The mine would be located in Caribou County approximately 18 miles northeast of Soda Springs, Idaho, on the southwestern flank of Rasmussen Ridge and adjacent to portions of Rasmussen Valley near the headwaters of the Blackfoot River.

The proposed Rasmussen Valley Mine would be developed on BLM-managed lands within an existing Federal phosphate lease; on National Forest System lands within and outside of an existing Federal phosphate lease with surface administered by the Soda Springs Ranger District, on the Blackfoot River Wildlife Management Area within and outside of the Federal phosphate lease with the surface administered by the Idaho Department of Fish and Game (IDFG), and on split estate, private land with minerals administered by the BLM. The Lease grants the lessee, Agrium in this case, exclusive rights to mine and otherwise dispose of the federally-owned phosphate deposit. Under the proposed action a lease modification would increase the size of the lease by 170 acres. A portion of the proposed action would also be outside of the Federal phosphate lease on State land administered by the Idaho Department of Lands (IDL).

As directed by the Mineral Leasing Act of 1920 and in accordance with NEPA, the BLM will evaluate and respond to the mine plan and issue decisions related to the development of the phosphate lease, consider the no action alternative, and decide whether to approve the proposed mine plan. The USFS will make recommendations to the BLM concerning surface management and mitigation on leased lands within the CTNF, and will make separate decisions on special use authorizations for off-lease activities within the CTNF. The BLM, as the Federal lease administrator, is the lead agency for the Draft EIS. The USFS is the joint-lead agency and the Idaho Department of Environmental Quality and U.S. Army Corps of Engineers are cooperating agencies. The IDL, IDFG, Idaho Department of Water Resources, and U.S. Fish and Wildlife Service have also participated in the preparation of the Draft EIS. The Draft EIS provides the analysis upon which the BLM and other involved agencies can base decisions regarding the project.

Under the Proposed Action, phosphate ore would be mined and hauled to Agrium's existing Wooley Valley Tipple, then by existing rail to Agrium's CPO Fertilizer Plant approximately 12 miles to the southwest. The Proposed Action would consist of using open pit mining methods to mine a pit in phases (panels), backfill and reclaim pits; construct permanent and temporary external overburden and ore piles, growth media stockpiles, haul roads; realign portions of the county roads; construct power lines, staging and fuel storage area, water supply wells, and runoff sediment control structures; leave high wall exposures in portions of the backfilled pit; and extend the pit and associated backfill beyond the Lease boundary in several locations requiring Lease modification.

A Notice of Intent to prepare this EIS was published in the **Federal Register** (76 FR 11259) on March 1, 2011, initiating a public scoping period for the Proposed Action. During scoping, issues and concerns that were expressed included impacts to wetlands; impacts to surface water and groundwater potentially resulting from releases of selenium and other constituents of potential concern (COPC) from waste rock; physical stability of proposed external overburden piles; management of pit water; impacts to wildlife and associated wildlife habitat, especially on the Blackfoot River Wildlife Management Area; and maximum phosphate resource recovery.

To address these issues, several alternatives were considered. Two of these alternatives, Alternative One—the Rasmussen Collaborative Alternative and the No Action Alternative, were carried forward for full analysis in the Draft EIS. Alternative One is the agency preferred alternative and would include 371.7 acres of new disturbance. Elements included in Alternative One are: Relocating the haul road to avoid wetlands; reducing the potential for selenium and other COPCs to impact surface water and groundwater by placing overburden originally scheduled for external overburden piles in an existing open pit at P4's nearby South Rasmussen Mine, resulting in the elimination of three external overburden piles and the associated concern for stability of the natural foundation under these piles and impacts to water resources by COPCs; limiting pit depth to reduce the concern for the management of pit water; shaping pit backfill and external overburden piles to reduce the risk of ponded water on or in the pit, and designing a cover to place over the backfill and overburden to reduce the risk of deep percolation of water; maximizing phosphate resource recovery by extending the pit north; reducing the size of the BLM lease modification contained in the Proposed Action to 100 acres while still accommodating extension of the mine pit, external overburden piles, temporary growth media stockpiles, and ancillary mine features beyond the current Lease boundaries. If the mine is extended, USFS Special Use Authorizations and State of Idaho Temporary Use Authorizations will also be needed.

Under the No Action Alternative, the Rasmussen Valley Mine Plan would not be approved for mining, and no associated development would occur on the existing lease. Similarly, associated requests such as the lease modification application would not be approved. The No Action Alternative would not provide ore for the CPO and would leave the mineral resource unmined. The resources would not be developed under the 2011 Proposed Action. However, the No Action Alternative does not preclude application and approval of future Mine and Reclamation Plans for the site because of pre-existing mining rights granted in the existing Lease.

To facilitate understanding and comments on the Draft EIS, public meetings are planned to be held in Soda Springs and Pocatello, Idaho. Meetings will be open-house style, with displays explaining the project and a forum for commenting on the draft EIS. The BLM will announce dates, times, and locations of the public scoping meetings in mailings and news releases.

Written and electronic comments regarding the Draft EIS should be submitted within 45 days of the date of publication of the Environmental Protection Agency's Notice of Availability in the **Federal Register**. To assist the BLM and the USFS in identifying issues and concerns related to this project, comments should be as specific as possible. The portion of the proposed project related to special use authorizations for off-lease activities is subject to the USFS's objection process pursuant to 36 CFR 218 Subparts A and B. Only those who provide comment concerning the off-lease activities during this comment period or who have previously submitted specific written comments on the off-lease activities, either during scoping or other designated opportunity for public comment, will be eligible as objectors to the off-lease activities (36 CFR 218.5). BLM appeal procedures found in 43 CFR 4 apply to the portion of the project related to activities proposed on the Federal mineral lease(s).

Please note that public comments and information submitted including names, street addresses, and email addresses of respondents will be available for public review and disclosure at the above BLM address during regular business hours (8 a.m. to 4 p.m.), Monday through Friday, except holidays.

Before including your 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.

Authority: 42 U.S.C. 4321 *et seq.* ; 40 CFR parts 1500–1508; 43 CFR part 46; 43 U.S.C. 1701; 43 CFR part 3510; and 43 CFR part 3590.

Jeremy Casterson,

Acting District Manager, Idaho Falls District, Bureau of Land Management.

Robert Mickelsen,

Forest Supervisor, Caribou-Targhee National Forest.

[FR Doc. 2015–23412 Filed 9–17–15; 8:45 am]

BILLING CODE P

DEPARTMENT OF THE INTERIOR

Bureau of Land Management

[AA–10731, AA–10785, AA–10786, AA–10788, AA–11135, AA–11146, AA–12448; LLAK–944000–L14100000–HY0000–P]

Alaska Native Claims Selection

AGENCY: Bureau of Land Management, Interior.

ACTION: Notice of Decision Approving Lands for Conveyance.

SUMMARY: Notice is hereby given that an appealable decision will be issued by the Bureau of Land Management (BLM), approving conveyance of the surface and subsurface estates in the lands described below to Chugach Alaska Corporation (formerly known as Chugach Natives, Inc.), pursuant to the Alaska Native Claims Settlement Act.

DATES: Any party claiming a property interest in the lands affected by the decision may appeal the decision in accordance with the requirements of 43 CFR part 4. Please see the **SUPPLEMENTARY INFORMATION** section for the time limits for appealing the decision.

ADDRESSES: A copy of the decision may be obtained from: Bureau of Land Management, Alaska State Office, 222 West Seventh Avenue, #13, Anchorage, AK 99513–7504.

FOR FURTHER INFORMATION CONTACT: The BLM by phone at 907–271–5960 or by email at *blm_ak_akso_public_room@blm.gov.* Persons who use a Telecommunications Device for the Deaf (TDD) may call the Federal Information Relay Service (FIRS) at 1–800–877–8339 to contact the BLM during normal business hours. In addition, the FIRS is available 24 hours a day, 7 days a week, to leave a message or question with the BLM. The BLM will reply during normal business hours.

SUPPLEMENTARY INFORMATION: As required by 43 CFR 2650.7(d), notice is hereby given that an appealable decision will be issued by the BLM to Chugach Alaska Corporation (formerly known as Chugach Natives, Inc.). The decision approves conveyance of the surface and subsurface estates in certain lands pursuant to the Alaska Native Claims Settlement Act (43 U.S.C. 1601, *et seq*). The lands are located in the Chugach National Forest, and contain/aggregate 80.78 acres. Notice of the decision will also be published once a week for four consecutive weeks in the *Alaska Dispatch News.*

Any party claiming a property interest in the lands affected by the decision may appeal the decision in accordance with the requirements of 43 CFR part 4 within the following time limits:

1. Unknown parties, parties unable to be located after reasonable efforts have been expended to locate, parties who fail or refuse to sign their return receipt, and parties who receive a copy of the decision by regular mail which is not certified, return receipt requested, shall have until October 19, 2015 to file an appeal.

2. Parties receiving service of the decision by certified mail shall have 30 days from the date of receipt to file an appeal.

Parties who do not file an appeal in accordance with the requirements of 43 CFR part 4 shall be deemed to have waived their rights. Notices of appeal transmitted by electronic means, such as facsimile or email, will not be accepted as timely filed.

Loch Anderson,

Land Law Examiner, Adjudication Section.

[FR Doc. 2015–23481 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–JA–P

DEPARTMENT OF THE INTERIOR

National Park Service

[NPS–NER–PAGR–18936; PX.P0156924I.00.1]

Notice of Termination of the Environmental Impact Statement for the General Management Plan for Paterson Great Falls National Historical Park, New Jersey

AGENCY: National Park Service, Interior.

ACTION: Notice of Termination.

SUMMARY: The National Park Service (NPS) is preparing a general management plan (GMP) for Paterson Great Falls National Historical Park. A Notice of Intent to prepare an environmental impact statement (EIS) for the GMP was published in the **Federal Register** on November 14, 2011. The NPS has decided to terminate the EIS and instead, has prepared an environmental assessment (EA) for the GMP (GMP/EA).

DATES: The GMP/EA is expected to be distributed for public review and comment during the fall of 2015. The NPS will provide information on when the GMP/EA will be released for public review, the dates of the public comment period, and the dates that public meetings will be held on the park's planning Web site at *http://parkplanning.nps.gov/pagr* and through local and regional media.

ADDRESSES: Refer to the park's planning Web site at *http://parkplanning.nps.gov/pagrforadditionalinformationonwhereandhowtoobtainacopyoftheGMP/EA*, how to comment on the GMP/EA, and locations of upcoming public meetings.

FOR FURTHER INFORMATION CONTACT: Darren Boch, Superintendent; Paterson Great Falls National Historical Park; 72 McBride Avenue; Paterson, NJ 07501.

SUPPLEMENTARY INFORMATION: This is Paterson Great Falls National Historical Park's first general management plan and will provide the framework for guiding resource management, visitor experiences, facilities and partnerships. The issues addressed by the GMP include: Sustaining the park's fundamental resources; providing for safe, sustainable public access and recreational activities; building new and reinforcing existing partnerships to protect the park's natural and cultural resources; and improving facilities and infrastructure that meets the needs of both visitors and the community. GMP planning and alternatives development incorporated input from park partners; participants in local community meetings; consultation with local, regional, and national government agencies; and comments gathered during the Paterson Great Falls Advisory Commission meetings. The public was informed about the process and invited to participate through the park's Web site, newsletters, emails, letters, and local media.

The GMP was originally scoped as an EIS; however, internal discussions and input received during public and agency scoping did not raise any potentially significant environmental issues nor has the impact analysis identified any potentially significant adverse impacts. It is also noted that many of the actions proposed in the GMP/EA will have benefits to the park's resources, operational needs, and visitor experiences. For these reasons the NPS determined that an EA is the appropriate level of environmental review for the GMP.

Dated: July 30, 2015.

Brian Strack,

Associate Regional Director; Planning, Facilities & Conservation Assistance, Northeast Region, National Park Service.

[FR Doc. 2015–23452 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–WV–P

DEPARTMENT OF THE INTERIOR

Bureau of Ocean Energy Management

[BOEM–2015–0078; MMAA104000]

Revised Environmental Assessment for Commercial Wind Lease Issuance and Site Assessment Activities on the Atlantic Outer Continental Shelf Offshore North Carolina

AGENCY: Bureau of Ocean Energy Management (BOEM), Interior.

ACTION: Notice of Availability.

SUMMARY: BOEM is announcing the availability of a revised Environmental Assessment (EA) and Finding of No Significant Impact (FONSI) for commercial wind lease issuance, site characterization activities (geophysical, geotechnical, archaeological, and biological surveys), and site assessment activities (including the installation and operation of a meteorological tower and/or buoys) on the Atlantic Outer Continental Shelf offshore North Carolina. The revised EA provides a discussion of potential impacts of the proposed action and an analysis of reasonable alternatives to the proposed action. In accordance with the requirements of the National Environmental Policy Act (NEPA) and the Council on Environmental Quality's (CEQ) regulations implementing NEPA (40 CFR parts 1500 through 1508), BOEM issued a FONSI supported by the analysis in the revised EA. The FONSI concluded that the reasonably foreseeable environmental impacts associated with the proposed action and alternatives, as set forth in the EA, would not significantly impact the quality of the human environment; therefore, the preparation of an Environmental Impact Statement is not required. These documents and associated information are available on BOEM's Web site at *http://www.boem.gov/North-Carolina/*.

FOR FURTHER INFORMATION CONTACT: Michelle Morin, BOEM Office of Renewable Energy Programs, 45600 Woodland Road, Sterling, Virginia 20166, (703) 787–1340 or *michelle.morin@boem.gov*.

SUPPLEMENTARY INFORMATION: In January 2015, BOEM published an EA to consider the reasonably foreseeable environmental consequences associated with commercial wind lease issuance, site characterization activities, and site assessment activities in three wind energy areas (WEAs) offshore North Carolina. The 2015 EA considered all three North Carolina WEAs for leasing and approval of site assessment plans as the proposed action under NEPA. A Notice of Availability was published on January 23, 2015 to announce the availability of the EA and initiate a 30-day public comment period (80 FR 3621). The EA was subsequently revised based on comments received during the comment period and public information meetings. The revised EA provides updated environmental data, additional details on how the WEAs were delineated, and analysis of potential effects to the proposed critical habitat expansion for North Atlantic right whales, which was published during the public comment period for the 2015 EA. A summary of comments received on the 2015 EA and BOEM's responses to those comments is also provided in the revised EA.

In addition to the proposed action, the revised EA considers the following alternatives: Exclusion of the Wilmington West WEA from leasing; seasonal restrictions on certain site characterization activities; and no action. BOEM's analysis of the proposed action and alternatives takes into account standard operating conditions (SOCs) designed to avoid or minimize potential impacts to marine mammals and sea turtles. The SOCs can be found in Appendix B of the revised EA.

BOEM will use the revised EA to inform decisions to issue leases in the North Carolina WEAs, and to subsequently approve site assessment plans on those leases. BOEM may issue one or more commercial wind energy leases in the North Carolina WEAs. The competitive leasing process is set forth at 30 CFR 585.210 through 585.225. If a lessee is prepared to propose a wind energy generation facility on its lease, the lessee can submit a Construction and Operations Plan (COP) to BOEM. BOEM would then prepare a separate site- and project-specific NEPA analysis based on the activities proposed in the COP.

Authority: This Notice of Availability for an EA is in compliance with the National Environmental Policy Act of 1969, as amended (42 U.S.C. 4231 *et seq.*), and is published pursuant to 43 CFR 46.305.

Dated: August 3, 2015.

Abigail Ross Hopper,

Director, Bureau of Ocean Energy Management.

[FR Doc. 2015–22988 Filed 9–17–15; 8:45 am]

BILLING CODE 4310–MR–P

UNITED STATES INTERNATIONAL TRADE COMMISSION

[USITC SE–15–031]

Government in the Sunshine Act Meeting Notice

AGENCY HOLDING THE MEETING: United States International Trade Commission.

TIME AND DATE: September 24, 2015 at 9 a.m.

PLACE: Room 101, 500 E Street SW., Washington, DC 20436, Telephone: (202) 205–2000.

STATUS: Open to the public.

MATTERS TO BE CONSIDERED:

1. Agendas for future meetings: None.
2. Minutes.
3. Ratification List.
4. Vote in Inv. Nos. 701–TA–545–547 and 731–TA–1291–1297 (Preliminary) (Certain Hot-Rolled Steel Flat Products from Australia, Brazil, Japan, Korea, the Netherlands, Turkey, and the United Kingdom). The Commission is currently scheduled to complete and file its determinations on September 25, 2015; views of the Commission are currently scheduled to be completed and filed on October 2, 2015.
5. Outstanding action jackets: None.

In accordance with Commission policy, subject matter listed above, not disposed of at the scheduled meeting, may be carried over to the agenda of the following meeting.

By order of the Commission.

Issued: September 15, 2015.

William R. Bishop,

Supervisory Hearings and Information Officer.

[FR Doc. 2015–23586 Filed 9–16–15; 4:15 pm]

BILLING CODE 7020–02–P

DEPARTMENT OF LABOR

Veterans' Employment and Training Service

Solicitation of Nominations for Appointment to the Advisory Committee on Veterans' Employment, Training, and Employer Outreach

AGENCY: Veterans' Employment and Training Service (VETS), Department of Labor (DOL).

ACTION: Notice.

SUMMARY: In accordance with section 4110 of Title 38, U.S. Code, and the provisions of the Federal Advisory Committee Act (FACA) and its implementing regulations issued by the U.S. General Services Administration (GSA), the Secretary of Labor (the Secretary), is seeking nominations of qualified candidates to be considered for appointment as a member of the Advisory Committee on Veterans' Employment, Training, and Employer Outreach (ACVETEO, or the Committee). The ACVETEO's responsibilities are to: (a) Assess employment and training needs of veterans and their integration into the workforce; (b) determine the extent to which the programs and activities of the Department are meeting such needs; (c) assist the Assistant Secretary for Veterans' Employment and Training (ASVET) in conducting outreach to employers with respect to the training and skills of veterans and the advantages afforded employers by hiring veterans; (d) make recommendations to the Secretary of Labor, through the ASVET, with respect to outreach activities and the employment and training needs of veterans; and (e) carry out such other activities deemed necessary to making required reports and recommendations under section 4110(f) of Title 38, U.S. Code. Per section 4110(c)(1) of Title 38, U.S. Code, the Secretary shall appoint at least twelve, but no more than sixteen, individuals to serve as Special Government Employees of the ACVETEO as follows: Seven individuals, one each from the following organizations: (i) The Society for Human Resource Management; (ii) the Business Roundtable; (iii) the National Association of State Workforce Agencies; (iv) the United States Chamber of Commerce; (v) the National Federation of Independent Business; (vi) a nationally recognized labor union or organization; and (vii) the National Governors Association. The Secretary shall appoint not more than five individuals nominated by veterans' service organizations that have a national employment program and not more than five individuals who are recognized authorities in the fields of business, employment, training, rehabilitation, or labor and who are not employees of DOL. The term of membership for all Committee members is February 1, 2016 through January 31, 2018.

DATES: Nominations for membership on the Committee must be received no later than 11:59 p.m. EST on October 15, 2015. Packages received after this time will not be considered for the current membership cycle. Please allow three weeks for regular mail delivery to the Department of Labor.

ADDRESSES: All nomination packages should be sent to the Assistant Designated Federal Official by email to *green.gregory.b@dol.gov* subject line ''2016 ACVETEO Nomination'' or mail to the following address: Department of Labor/VETS, Attn: Gregory Green, Room S–1312, 200 Constitution Ave. NW., Washington, DC 20210.

FOR MORE INFORMATION CONTACT: Gregory B. Green, Assistant Designated Federal Official, ACVETEO, U.S. Department of Labor, 200 Constitution Ave. NW., Room S–1312, Washington, DC 20210; telephone (202) 693–4734.

SUPPLEMENTARY INFORMATION: DOL is soliciting nominations for members to serve on the Committee. As required by statute, the members of the Committee are appointed by the Secretary from the general public. DOL seeks nominees with the following experience:

(1) Diversity in professional and personal qualifications;

(2) Experience in military service);

(3) Current work with Veterans;

(4) Veterans disability subject matter expertise;

(5) Experience working in large and complex organizations;

(6) Experience in transition assistance;

(7) Experience in the protection of employment and reemployment rights; and/or

(8) Experience in education, skills training, integration into the workforce and outreach.

Requirements for Nomination Submission: Nominations should be typewritten (one nomination per nominator). The nomination package should include:

(1) Letter of nomination that clearly states the name and affiliation of the nominee, the basis for the nomination (*i.e.,* specific attributes, including military service, if applicable, that qualifies the nominee for service in this capacity);

(2) Statement from the nominee indicating willingness to regularly attend and participate in Committee meetings;

(3) Nominee's contact information, including name, mailing address, telephone number(s), and email address;

(4) Nominee's curriculum vitae or resume;

(5) Summary of the nominee's experience and qualifications relative to the experience listed above;

(6) Nominee biography; and

(7) Statement that the nominee has no apparent conflicts of interest that would preclude membership.

Individuals selected for appointment to the Committee will be reimbursed for per diem and travel for attending Committee meetings. The Department makes every effort to ensure that the membership of its Federal advisory committees is fairly balanced in terms of points of view represented. Every effort is made to ensure that a broad representation of geographic areas, gender, and racial and ethnic minority groups, and that the disabled are given consideration for membership. Appointment to this Committee shall be made without discrimination because of a person's race, color, religion, sex (including gender identity, transgender status, sexual orientation, and pregnancy), national origin, age, disability, or genetic information. An ethics review is conducted for each selected nominee.

Signed at Washington, DC, on September 11, 2015.

Teresa W. Gerton,

Acting Assistant Secretary for Veterans' Employment and Training.

[FR Doc. 2015–23411 Filed 9–17–15; 8:45 am]

BILLING CODE 4510–79–P

DEPARTMENT OF LABOR

Wage and Hour Division

Agency Information Collection Activities; Comment Request; Information Collections Requests To Approve Conformed Wage Classifications and Unconventional Fringe Benefit Plans Under the Davis-Bacon and Related Acts and Contract Works Hours and Safety Standards Act

AGENCY: Wage and Hour Division, Department of Labor.

ACTION: Notice.

SUMMARY: The Department of Labor (DOL) is soliciting comments concerning a proposed revision to the information collection request (ICR) titled, ''Requests to Approve Conformed Wage Classifications and Unconventional Fringe Benefit Plans Under the Davis-Bacon and Related Acts and Contract Works Hours and Safety Standards Act.'' This comment request is part of continuing Departmental efforts to reduce paperwork and respondent burden in accordance with the Paperwork Reduction Act of 1995 (PRA), 44 U.S.C. 3501 *et seq.*

This program helps to ensure that requested data can be provided in the desired format, reporting burden (time and financial resources) is minimized, collection instruments are clearly understood, and the impact of collection requirements on respondents can be properly assessed. A copy of the proposed information request can be obtained by contacting the office listed below in the **FOR FURTHER INFORMATION CONTACT** section of this Notice.

DATES: Written comments must be submitted to the office listed in the **ADDRESSES** section below on or before November 17, 2015.

ADDRESSES: You may submit comments identified by Control Number 1235–0023, by either one of the following methods: *Email: WHDPRAComments@dol.gov; Mail, Hand Delivery, Courier:* Division of Regulations, Legislation, and Interpretation, Wage and Hour, U.S. Department of Labor, Room S–3502, 200 Constitution Avenue NW., Washington, DC 20210. *Instructions:* Please submit one copy of your comments by only one method. All submissions received must include the agency name and Control Number identified above for this information collection. Because we continue to experience delays in receiving mail in the Washington, DC area, commenters are strongly encouraged to transmit their comments electronically via email or to submit them by mail early. Comments, including any personal information provided, become a matter of public record. They will also be summarized and/or included in the request for Office of Management and Budget (OMB) approval of the information collection request.

FOR FURTHER INFORMATION CONTACT: Robert Waterman, Acting Director, Division of Regulations, Legislation, and Interpretation, Wage and Hour Division, U.S. Department of Labor, Room S–3502, 200 Constitution Avenue NW., Washington, DC 20210; telephone: (202) 693–0406 (this is not a toll-free number). Copies of this notice may be obtained in alternative formats (Large Print, Braille, Audio Tape, or Disc), upon request, by calling (202) 693–0023 (not a toll-free number). TTY/TTD callers may dial toll-free (877) 889–5627 to obtain information or request materials in alternative formats.

SUPPLEMENTARY INFORMATION:

I. Background: The Wage and Hour Division (WHD) of the Department of Labor (DOL) administers the Davis-Bacon Act (DBA) and Davis-Bacon Related Acts (DBRA), 40 U.S.C. 3141 *et seq.,* and the Contract Work Hours and Safety Standards Act (CWHSSA), 40 U.S.C. 3701*et seq.* Regulations 29 CFR part 5 prescribe labor standards for federally financed and assisted construction contracts subject to the Davis-Bacon Act, the Davis-Bacon Related Acts, and labor standards for all contracts subject to the Contract Work Hours and Safety Standards Act. The DBA and DBRA require payment of locally prevailing wages and fringe benefits, as determined by the Department of Labor, to laborers and mechanics on most federally financed or assisted construction projects. The CWHSSA requires the payment of one and one-half times the basic rate of pay for hours worked over forty in a week on most federal contracts involving the employment of laborers or mechanics. The requirements of this information collection consist of: (1) Reports of conformed classifications and wage rates, and (2) requests for approval of unfunded fringe benefit plans.

II. Review Focus: The Department of Labor is particularly interested in comments which:

- 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;
- Enhance the quality, utility, and clarity of the information to be collected;

• 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;

• 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 submissions of responses.

III. Current Actions: The Department of Labor seeks an approval for the extension of this information collection in order to ensure effective administration of the government contract programs.

Type of Review: Extension.

Agency: Wage and Hour Division.

Title: Requests to Approve Conformed Wage Classifications and Unconventional Fringe Benefit Plans Under the Davis-Bacon and Related Acts and Contract Works Hours and Safety Standards Act

OMB Number: 1235–0023.

Affected Public: Business or other for-profit, Not-for-profit institutions, Farms, State, Local, or Tribal Government.

Total Respondents: 8,500 Conformance Reports, 3 Unfunded Fringe Benefit Plans.

Total Annual Responses: 8,500 Conformance Reports, 3 Unfunded Fringe Benefit Plans.

Estimated Total Burden Hours: 2,125 hours (Conformance Reports), 3 hours (Unfunded Fringe Benefit Plans).

Estimated Time per Response: 15 minutes (Conformance Report), 1 hour (Unfunded Fringe Benefit Plans).

Frequency: On occasion.

Total Burden Cost (capital/startup): $4,422.

Total Burden Cost (operation/maintenance): $58,499.

Dated: September 12, 2015.

Mary Ziegler,

Assistant Administrator for Policy.

[FR Doc. 2015–23413 Filed 9–17–15; 8:45 am]

BILLING CODE 4510–27–P

NATIONAL AERONAUTICS AND SPACE ADMINISTRATION

[Notice: (15–077)]

NASA Aerospace Safety Advisory Panel; Meeting

AGENCY: National Aeronautics and Space Administration (NASA).

ACTION: Notice of Meeting.

SUMMARY: In accordance with the Federal Advisory Committee Act, Public Law 92–463, as amended, the National Aeronautics and Space Administration announces a forthcoming meeting of the Aerospace Safety Advisory Panel.

DATES: Wednesday, October 7, 2015, 12:00 p.m. to 1:30 p.m., Local Time.

ADDRESSES: NASA Johnson Space Center, Room 966, NASA Parkway, Building 1, Houston, TX 77058.

FOR FURTHER INFORMATION CONTACT: Ms. Marian Norris, Aerospace Safety Advisory Panel Administrative Officer, NASA Headquarters, Washington, DC 20546, (202) 358–4452, or email at *mnorris@nasa.gov.*

SUPPLEMENTARY INFORMATION: The Aerospace Safety Advisory Panel (ASAP) will hold its Fourth Quarterly Meeting for 2015. This discussion is pursuant to carrying out its statutory duties for which the Panel reviews, identifies, evaluates, and advises on those program activities, systems, procedures, and management activities that can contribute to program risk. Priority is given to those programs that involve the safety of human flight. The agenda will include:

- Updates on the Exploration Systems Development
- Updates on the Commercial Crew Program
- Updates on the International Space Station Program

The meeting will be open to the public up to the seating capacity of the room. Seating will be on a first-come basis. This meeting is also available telephonically. Any interested person may call the USA toll free conference call number (800) 857–7040; pass code 8712653. Attendees will be required to sign a visitor's register and to comply with NASA security requirements, including the presentation of a valid picture ID, before receiving an access badge. Due to the Real ID Act, Public Law 109–13, any attendees with driver's licenses issued from non-compliant states/territories must present a second form of ID (Federal employee badge; passport; active military identification card; enhanced driver's license; U.S. Coast Guard Merchant Mariner card; Native American tribal document; school identification accompanied by an item from LIST C (documents that establish employment authorization) from the ''List of the Acceptable Documents'' on Form I–9). Non-compliant states/territories are: American Samoa, Arizona, Idaho, Louisiana, Maine, Minnesota, New Hampshire, and New York. Any member of the public desiring to attend the ASAP 2015 Fourth Quarterly Meeting at the Johnson Space Center must provide their full name and company affiliation (if applicable) to Ms. Stephanie Castillo at *stephanie.m.castillo@nasa.gov* or by fax 281–483–2200 or telephone 281–483–3341 by September 29, 2015. Foreign Nationals attending the meeting will be required to provide a copy of their passport and visa, in addition to providing the following information by September 21, 2015: Full name; gender; date/place of birth; citizenship; visa information (number, type, expiration date); passport information (number, country, expiration date); employer/affiliation information (name of institution, address, country, telephone); and title/position of attendee. Additional information may be requested. Permanent Residents should provide this information: Green card number and expiration date. Persons with disabilities who require assistance should indicate this. Photographs will only be permitted during the first 10 minutes of the meeting.

At the beginning of the meeting, members of the public may make a verbal presentation to the Panel on the subject of safety in NASA, not to exceed 5-minutes in length. To do so, members of the public must contact Ms. Marian Norris at *mnorris@nasa.gov* or at (202) 358–4452 at least 48 hours in advance. Any member of the public is permitted to file a written statement with the Panel at the time of the meeting. Verbal presentations and written comments should be limited to the subject of safety in NASA. It is imperative that the meeting be held on this date to accommodate the scheduling priorities of the key participants.

Patricia D. Rausch,

Advisory Committee Management Officer, National Aeronautics and Space Administration.

[FR Doc. 2015–23376 Filed 9–17–15; 8:45 am]

BILLING CODE 7510–13–P

NATIONAL SCIENCE FOUNDATION

Committee on Equal Opportunities in Science and Engineering; Notice of Meeting

In accordance with the Federal Advisory Committee Act (Pub. L. 92–463, as amended), the National Science Foundation announces the following meeting:

Name: Committee on Equal Opportunities in Science and Engineering (1173).

Dates/Time: October 15, 2015, 10:00 a.m.–12 Noon and 1:00 p.m.–4:00 p.m.

Place: National Science Foundation (NSF), 4201 Wilson Boulevard, Room 1235, Arlington, VA 22230.

Note: CEOSE AC members will participate *virtually.* If you are interested in attending this meeting, you are required to attend in person. To help facilitate your entry into the building, please contact Victoria Fung (*vfung@nsf.gov*) on or prior to October 13, 2015.

Type of Meeting: Open.

Contact Person: Dr. Bernice T. Anderson, Senior Advisor and CEOSE Executive Secretary, Office of Integrative Activities (OIA), National Science Foundation, 4201 Wilson Boulevard, Arlington, VA 22230, (703) 292–8040 (main), Email Address: *banderso@nsf.gov.*

Minutes: Meeting minutes and other information may be obtained from the CEOSE Executive Secretary at the above address or the Web site at *http://www.nsf.gov/od/oia/activities/ceose/index.jsp.*

Purpose of Meeting: To study data, programs, policies, and other information pertinent to the National Science Foundation and to provide advice and recommendations concerning broadening participation in science and engineering.

Agenda (Tentative): Please access CEOSE Web site, *http://www.nsf.gov/od/oia/activities/ceose/index.jsp* for final version.

Thursday, October 15, 2015

Opening Statement by the CEOSE Chair Presentations and Discussions:

- Update of NSF Broadening Participation Activities by the CEOSE Executive Liaison
- Presentation of Inclusion across the Nation of Communities of Learners that have been Underrepresented for Diversity in Engineering and Science (NSF INCLUDES)
- Discussion with Dr. France Córdova, Director and Dr. Richard Buckius, Chief Operating Officer of the National Science Foundation
- Reports of CEOSE Liaisons to NSF Advisory Committees
- Updates by Federal Agency Liaisons About Interagency Broadening Participation Activities
- Presentation of NSF Evaluation and Assessment Capability (EAC)
- Production of the 2015–2016 CEOSE Biennial Report to Congress

Dated: September 14, 2015.

Crystal Robinson,

Committee Management Officer.

[FR Doc. 2015–23437 Filed 9–17–15; 8:45 am]

BILLING CODE 7555–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 50–461; NRC–2015–0221]

Clinton Power Station, Unit 1

AGENCY: Nuclear Regulatory Commission.

ACTION: License amendment application; opportunity to request a hearing and to petition for leave to intervene.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) has received an application dated September 5, 2015, from Exelon Generation Company, LLC, for amendment of Clinton Power Station, Unit 1. The application proposes a one-time extension from 72 hours to 7 days of the technical specification (TS) completion time [CT] associated with the Division 2 (Div. 2) Shutdown Service Water (SX) Subsystem in support maintenance activities.

DATES: Submit comments by October 19, 2015. Requests for a hearing or petition for leave to intervene must be filed by November 17, 2015.

ADDRESSES: Please refer to Docket ID NRC–2015–0221 when contacting the NRC about the availability of information regarding this document. You may obtain publicly-available information related to this document using any of the following methods:

Federal Rulemaking Web site: Go to *http://www.regulations.gov* and search for Docket ID NRC–2015–0221. Address questions about NRC dockets to Carol Gallagher; telephone: 301–415–3463; email: *Carol.Gallagher@nrc.gov.* For technical questions, contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.

- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''*ADAMS Public Documents*'' and then select ''*Begin Web-based ADAMS Search.*'' For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* The ADAMS accession number for each document referenced in this document (if that document is available in ADAMS) is provided the first time that a document is referenced.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

FOR FURTHER INFORMATION CONTACT: Eva A. Brown, Office of Nuclear Reactor Regulation, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001; telephone: 301–415–2315; email: *Eva.Brown@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Introduction

The NRC is considering issuance of an amendment to Facility Operating License No. NPF–62, issued to Clinton Power Station, Unit 1, located in DeWitt County, Illinois. The proposed amendment proposes a one-time extension from 72 hours to 7 days of the technical specification (TS) completion time [CT] associated with the Division 2 (Div. 2) Shutdown Service Water (SX) Subsystem in support maintenance activities.

Before any issuance of the proposed license amendment, the NRC will need to make the findings required by the Atomic Energy Act of 1954, as amended (the Act), and NRC's regulations.

The NRC has made a proposed determination that the license amendment request involves no significant hazards consideration. Under the NRC's regulations in § 50.92 of Title 10 of the *Code of Federal Regulations* (10 CFR), this means that operation of the facility in accordance with the proposed amendment would not (1) involve a significant increase in the probability or consequences of an accident previously evaluated; or (2) create the possibility of a new or different kind of accident from any accident previously evaluated; or (3) involve a significant reduction in a margin of safety. As required by 10 CFR 50.91(a), the licensee has provided its analysis of the issue of no significant hazards consideration, which is presented below:

1. Does the proposed change involve a significant increase in the probability or consequences of an accident previously evaluated?

Response: No.

The proposed one-time change to the CT for CPS TS 3.7.1 will not increase the probability of an accident since it will only extend the time period that one SX subsystem can be out of service. The extension of the time duration that one SX subsystem is out of service has no direct physical impact on the plant. The proposed inoperable SX subsystem is normally in a standby mode while CPS is in Mode 1, 2, or 3 and is not directly supporting plant operation. Therefore, it can have no impact on the plant that would make an accident more likely to occur due to its inoperability. The proposed change does not adversely affect accident initiators or precursors, nor does it alter the design assumptions, conditions, or configuration of the facility or the manner in which the plant is operated and maintained.

The previously analyzed accidents are initiated by the failure of plant structures, systems, or components. The SX system is not considered an initiator for any of these previously analyzed events. The proposed change does not have a detrimental impact on the integrity of any plant structure, system, or component that initiates an analyzed event. No active or passive failure mechanisms that could lead to an accident are affected. The proposed change will not alter the operation of, or otherwise increase the failure probability of any plant equipment that initiates an analyzed accident. Therefore, the proposed change does not involve a significant increase in the probability of an accident previously evaluated.

The proposed change does not alter or prevent the ability of structures, systems, and components (SSCs) from performing their intended function to mitigate the consequences of an initiating event within the assumed acceptance limits. The proposed change does not require any physical change to any plant SSCs nor does it require any change in systems or plant operations. The proposed onetime increase in the CT is consistent with the philosophy of the current TS LCO which allows one SX subsystem to be inoperable for 72 hours. This change only extends the 72 hour CT to 7 days which has been shown to be acceptable from a risk perspective. The minimum equipment required to mitigate the consequences of an accident and/or safely shut down the plant will be Operable or available during the extended CT. The proposed change is consistent with the safety analysis assumptions and resultant consequences. Based on the above, the proposed change does not involve a significant increase in the consequences of an accident previously evaluated. Therefore, the proposed change does not involve a significant increase in the probability or consequences of an accident previously evaluated.

2. Does the proposed change create the possibility of a new or different kind of accident from any accident previously evaluated?

Response: No.

The proposed changes do not involve the use or installation of new equipment and the currently installed equipment will not be operated in a new or different manner. No new or different system interactions are created and no new processes are introduced. The proposed changes will not introduce any new failure mechanisms, malfunctions, or accident initiators not already considered in the design and licensing bases. Based on this evaluation, the proposed change does not create the possibility of a new or different kind of accident from any accident previously evaluated.

Therefore, the proposed change does not create the possibility of a new or different kind of accident from any previously evaluated.

3. Does the proposed change involve a significant reduction in a margin of safety?

Response: No.

The proposed change does not alter any existing setpoints at which protective actions are initiated and no new setpoints or protective actions are introduced. The design and operation of the SX system remains unchanged. The risk associated with the proposed increase in the time an SX pump is allowed to be inoperable was evaluated using the risk-informed processes described in RG 1.174 and RG 1.177. The risk was shown to be acceptable. Based on this evaluation, the proposed change does not involve a significant reduction in a margin of safety.

The NRC staff has reviewed the licensee's analysis and, based on this review, it appears that the three standards of 10 CFR 50.92(c) are satisfied. Therefore, the NRC staff proposes to determine that the license amendment request involves a No Significant Hazards Consideration.

The NRC is seeking public comments on this proposed determination that the license amendment request involves no significant hazards consideration. Any comments received within 30 days after the date of publication of this notice will be considered in making any final determination.

Normally, the Commission will not issue the amendment until the expiration of 60 days after the date of publication of this notice. The Commission may issue the license amendment before expiration of the 60-day notice period if the Commission concludes the amendment involves no significant hazards consideration. In addition, the Commission may issue the amendment prior to the expiration of the 30-day comment period should circumstances change during the 30-day comment period such that failure to act in a timely way would result, for example, in derating or shutdown of the facility. Should the Commission take action prior to the expiration of either the comment period or the notice period, it will publish in the **Federal Register** a notice of issuance. Should the Commission make a final No Significant Hazards Consideration Determination, any hearing will take place after issuance. The Commission expects that the need to take this action will occur very infrequently.

II. Opportunity To Request a Hearing and Petition for Leave To Intervene

Within 60 days after the date of publication of this **Federal Register** notice, any person whose interest may be affected by this proceeding and who desires to participate as a party in the proceeding must file a written request for hearing or a petition for leave to intervene specifying the contentions which the person seeks to have litigated in the hearing with respect to the license amendment request. Requests for hearing and petitions for leave to intervene shall be filed in accordance with the NRC's ''Agency Rules of Practice and Procedure'' in 10 CFR part 2. Interested person(s) should consult a current copy of 10 CFR 2.309, which is available at the NRC's PDR. The NRC's regulations are accessible electronically from the NRC Library on the NRC's Web site at *http://www.nrc.gov/reading-rm/doc-collections/cfr/*.

As required by 10 CFR 2.309, a request for hearing or petition for leave to intervene must set forth with particularity the interest of the petitioner in the proceeding and how that interest may be affected by the results of the proceeding. The hearing request or petition must specifically explain the reasons why intervention should be permitted, with particular reference to the following general requirements: (1) The name, address, and telephone number of the requestor or petitioner; (2) the nature of the requestor's/petitioner's right under the Act to be made a party to the proceeding; (3) the nature and extent of the requestor's/petitioner's property, financial, or other interest in the proceeding; and (4) the possible effect of any decision or order which may be entered in the proceeding on the requestor's/petitioner's interest. The hearing request or petition must also include the specific contentions that the requestor/petitioner seeks to have litigated at the proceeding.

For each contention, the requestor/petitioner must provide a specific statement of the issue of law or fact to be raised or controverted, as well as a brief explanation of the basis for the contention. Additionally, the requestor/petitioner must demonstrate that the issue raised by each contention is within the scope of the proceeding and is material to the findings that the NRC must make to support the granting of a license amendment in response to the application. The hearing request or petition must also include a concise statement of the alleged facts or expert opinion that support the contention and on which the requestor/petitioner intends to rely at the hearing, together with references to those specific sources and documents. The hearing request or petition must provide sufficient information to show that a genuine dispute exists with the applicant on a material issue of law or fact, including references to specific portions of the application for amendment that the petitioner disputes and the supporting reasons for each dispute. If the requestor/petitioner believes that the application for amendment fails to contain information on a relevant matter as required by law, the requestor/petitioner must identify each failure and the supporting reasons for the requestor's/petitioner's belief. Each contention must be one which, if proven, would entitle the requestor/

petitioner to relief. A requestor/petitioner who does not satisfy these requirements for at least one contention will not be permitted to participate as a party.

Those permitted to intervene become parties to the proceeding, subject to any limitations in the order granting leave to intervene, and have the opportunity to participate fully in the conduct of the hearing with respect to resolution of that person's admitted contentions, including the opportunity to present evidence and to submit a cross-examination plan for cross-examination of witnesses, consistent with NRC regulations, policies, and procedures. The Atomic Safety and Licensing Board will set the time and place for any prehearing conferences and evidentiary hearings, and the appropriate notices will be provided.

Hearing requests or petitions for leave to intervene must be filed no later than 60 days from the date of publication of this notice. Requests for hearing, petitions for leave to intervene, and motions for leave to file new or amended contentions that are filed after the 60-day deadline will not be entertained absent a determination by the presiding officer that the filing demonstrates good cause by satisfying the three factors in 10 CFR 2.309(c)(1)(i)–(iii).

If a hearing is requested, the Commission will make a final determination on the issue of no significant hazards consideration. The final determination will serve to decide when the hearing is held. If the final determination is that the amendment request involves no significant hazards consideration, the Commission may issue the amendment and make it immediately effective, notwithstanding the request for a hearing. Any hearing held would take place after issuance of the amendment. If the final determination is that the amendment request involves a significant hazards consideration, then any hearing held would take place before the issuance of any amendment unless the Commission finds an imminent danger to the health or safety of the public, in which case it will issue an appropriate order or rule under 10 CFR part 2.

III. Electronic Submissions (E-Filing)

All documents filed in NRC adjudicatory proceedings, including a request for hearing, a petition for leave to intervene, any motion or other document filed in the proceeding prior to the submission of a request for hearing or petition to intervene, and documents filed by interested governmental entities participating under 10 CFR 2.315(c), must be filed in accordance with the NRC's E-Filing rule (72 FR 49139; August 28, 2007). The E-Filing process requires participants to submit and serve all adjudicatory documents over the internet, or in some cases to mail copies on electronic storage media. Participants may not submit paper copies of their filings unless they seek an exemption in accordance with the procedures described below.

To comply with the procedural requirements of E-Filing, at least ten 10 days prior to the filing deadline, the participant should contact the Office of the Secretary by email at *hearing.docket@nrc.gov*, or by telephone at 301–415–1677, to request (1) a digital identification (ID) certificate, which allows the participant (or its counsel or representative) to digitally sign documents and access the E-Submittal server for any proceeding in which it is participating; and (2) advise the Secretary that the participant will be submitting a request or petition for hearing (even in instances in which the participant, or its counsel or representative, already holds an NRC-issued digital ID certificate). Based upon this information, the Secretary will establish an electronic docket for the hearing in this proceeding if the Secretary has not already established an electronic docket.

Information about applying for a digital ID certificate is available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals/getting-started.html.* System requirements for accessing the E-Submittal server are detailed in the NRC's ''Guidance for Electronic Submission,'' which is available on the agency's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* Participants may attempt to use other software not listed on the Web site, but should note that the NRC's E-Filing system does not support unlisted software, and the NRC Meta System Help Desk will not be able to offer assistance in using unlisted software.

If a participant is electronically submitting a document to the NRC in accordance with the E-Filing rule, the participant must file the document using the NRC's online, Web-based submission form. In order to serve documents through the Electronic Information Exchange System, users will be required to install a Web browser plug-in from the NRC's Web site. Further information on the Web-based submission form, including the installation of the Web browser plug-in, is available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.*

Once a participant has obtained a digital ID certificate and a docket has been created, the participant can then submit a request for hearing or petition for leave to intervene. Submissions should be in Portable Document Format (PDF) in accordance with NRC guidance available on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html.* A filing is considered complete at the time the documents are submitted through the NRC's E-Filing system. To be timely, an electronic filing must be submitted to the E-Filing system no later than 11:59 p.m. Eastern Time on the due date. Upon receipt of a transmission, the E-Filing system time-stamps the document and sends the submitter an email notice confirming receipt of the document. The E-Filing system also distributes an email notice that provides access to the document to the NRC's Office of the General Counsel and any others who have advised the Office of the Secretary that they wish to participate in the proceeding, so that the filer need not serve the documents on those participants separately. Therefore, applicants and other participants (or their counsel or representative) must apply for and receive a digital ID certificate before a hearing request/petition to intervene is filed so that they can obtain access to the document via the E-Filing system.

A person filing electronically using the NRC's adjudicatory E-Filing system may seek assistance by contacting the NRC Meta System Help Desk through the ''Contact Us'' link located on the NRC's public Web site at *http://www.nrc.gov/site-help/e-submittals.html,* by email to *MSHD.Resource@nrc.gov*, or by a toll-free call at 1–866–672–7640. The NRC Meta System Help Desk is available between 8 a.m. and 8 p.m., Eastern Time, Monday through Friday, excluding government holidays.

Participants who believe that they have a good cause for not submitting documents electronically must file an exemption request, in accordance with 10 CFR 2.302(g), with their initial paper filing requesting authorization to continue to submit documents in paper format. Such filings must be submitted by: (1) First class mail addressed to the Office of the Secretary of the Commission, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, Attention: Rulemaking and Adjudications Staff; or (2) courier, express mail, or expedited delivery service to the Office of the Secretary, Sixteenth Floor, One White Flint North, 11555 Rockville Pike, Rockville, Maryland, 20852, Attention: Rulemaking and Adjudications Staff. Participants filing a document in this manner are responsible for serving the document on all other participants. Filing is considered complete by first-class mail as of the time of deposit in the mail, or by courier, express mail, or expedited delivery service upon depositing the document with the provider of the service. A presiding officer, having granted an exemption request from using E-Filing, may require a participant or party to use E-Filing if the presiding officer subsequently determines that the reason for granting the exemption from use of E-Filing no longer exists.

Documents submitted in adjudicatory proceedings will appear in the NRC's electronic hearing docket which is available to the public at *http://ehd1.nrc.gov/ehd/*, unless excluded pursuant to an order of the Commission, or the presiding officer. Participants are requested not to include personal privacy information, such as social security numbers, home addresses, or home phone numbers in their filings, unless an NRC regulation or other law requires submission of such information. However, in some instances, a request to intervene will require including information on local residence in order to demonstrate a proximity assertion of interest in the proceeding. With respect to copyrighted works, except for limited excerpts that serve the purpose of the adjudicatory filings and would constitute a Fair Use application, participants are requested not to include copyrighted materials in their submission.

Petitions for leave to intervene must be filed no later than 60 days from the date of publication of this notice. Requests for hearing, petitions for leave to intervene, and motions for leave to file new or amended contentions that are filed after the 60-day deadline will not be entertained absent a determination by the presiding officer that the filing demonstrates good cause by satisfying the three factors in 10 CFR 2.309(c)(1)(i)–(iii).

For further details with respect to this action, see the application for license amendment dated September 11, 2015.

Attorney for licensee: Bradley J. Fewell, Associate General Counsel, Exelon Nuclear, 4300 Winfield Road, Warrenville, IL 60555.

NRC Branch Chief: Travis L. Tate.

Dated at Rockville, Maryland, this 15th day of September 2015.

For the Nuclear Regulatory Commission.

Eva A. Brown,

Senior Project Manager, Plant Licensing III–2 and Planning and Analysis Branch, Division of Operating Reactor Licensing, Office of Nuclear Reactor Regulation.

[FR Doc. 2015–23632 Filed 9–17–15; 8:45 am]

BILLING CODE 7590–01–P

NUCLEAR REGULATORY COMMISSION

[Docket No. 63–001–HLW; NRC–2015–0051]

Department of Energy; Yucca Mountain, Nye County, Nevada; Correction

AGENCY: Nuclear Regulatory Commission.

ACTION: Draft supplement to environmental impact statements; extension of comment period, public meeting, and correction.

SUMMARY: On August 21, 2015, the U.S. Nuclear Regulatory Commission (NRC) requested public comment on NUREG–2184, the NRC staff's draft ''Supplement to the U.S. Department of Energy's Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada'' (draft supplement). The public comment period was originally scheduled to close on October 20, 2015. The NRC staff has decided to extend the public comment period to allow more time for members of the public to develop and submit their comments. The NRC is also correcting its August 21, 2015, notice to correct a meeting date and Web site link.

DATES: The due date for comments on the draft supplement is extended. Comments should be filed no later than November 20, 2015. Comments received after this date will be considered, if it is practical to do so, but the Commission is able to ensure consideration only for comments received on or before this date.

The correction is effective September 18, 2015.

The NRC will hold a public meeting via teleconference to accept comments on the draft supplement on November 12, 2015, in addition to the teleconference being held on October 15, 2015. For additional information about this public meeting, see Section III, ''Public Meetings,'' of this document.

ADDRESSES: You may submit comments by any of the following methods (unless this document describes a different method for submitting comments on a specific subject):

- Federal Rulemaking Web site: Go to *http://www.regulations.gov* and search for Docket ID NRC–2015–0051. Address questions about NRC dockets to Carol Gallagher; telephone: 301–415–3463; email: *Carol.Gallagher@nrc.gov.* For technical questions, contact the individual listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.
- Mail comments to: Cindy Bladey, Office of Administration, Mail Stop: OWFN–12–H08, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

For additional direction on obtaining information and submitting comments, see ''Obtaining Information and Submitting Comments'' in the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Christine Pineda, Office of Nuclear Material Safety and Safeguards, U.S. Nuclear Regulatory Commission, Washington DC 20555–0001; telephone: 301–415–6789; email: *YMEIS_Supplement@nrc.gov.*

SUPPLEMENTARY INFORMATION:

I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2015–0051 when contacting the NRC about the availability of information for this action. You may obtain publicly-available information related to this action by any of the following methods:

- Federal rulemaking Web site: Go to *http://www.regulations.gov* and search for Docket ID NRC–2015–0051.
- NRC's Agencywide Documents Access and Management System (ADAMS): You may obtain publicly-available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select ''*ADAMS Public Documents''* and then select ''*Begin Web-based ADAMS Search.''* For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* The ADAMS accession number for each document referenced (if it is available in ADAMS) is provided the first time that it is mentioned in the **SUPPLEMENTARY INFORMATION** section.
- NRC's PDR: You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

B. Submitting Comments

Please include Docket ID NRC–2015–0051 in your comment submission.

The NRC cautions you not to include identifying or contact information that you do not want to be publicly disclosed in your comment submission. The NRC will post all comment submissions at *http://www.regulations.gov* as well as enter the comment submissions into ADAMS. The NRC does not routinely edit comment submissions to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the NRC, then you should inform those persons not to include identifying or contact information that they do not want to be publicly disclosed in their comment submission. Your request should state that the NRC does not routinely edit comment submissions to remove such information before making the comment submissions available to the public or entering the comment into ADAMS.

II. Discussion

A. Comment Period Extension

On August 21, 2015 (80 FR 50875), the NRC requested public comments on NUREG–2184, the NRC staff's draft ''Supplement to the U.S. Department of Energy's Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada'' (ADAMS Accession No. ML15223B243). The supplement evaluates the potential environmental impacts on groundwater and impacts associated with the discharge of any contaminated groundwater to the ground surface due to potential releases from a geologic repository for spent nuclear fuel and high-level radioactive waste at Yucca Mountain, Nye County, Nevada. This supplements the U.S. Department of Energy's 2002 ''Final Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada'' (ADAMS Accession No. ML032690321), and 2008 ''Final Supplemental Environmental Impact Statement for a Geologic Repository for the Disposal of Spent Nuclear Fuel and High-Level Radioactive Waste at Yucca Mountain, Nye County, Nevada'' (ADAMS Accession No. ML081750191), in accordance with the findings and scope outlined in the NRC staff's 2008 ''Adoption Determination Report for the U.S. Department of Energy's Environmental Impact Statements for the Proposed Geologic Repository at Yucca Mountain'' (ADAMS Accession No. ML082420342). The public comment period was originally scheduled to close on October 20, 2015. The NRC received requests to extend the public comment period (*e.g.,* ADAMS Accession Nos. ML15253A864 and ML15253A874) and the NRC staff has decided to extend the public comment period on the draft supplement until November 20, 2015, to allow more time for members of the public to develop and submit their comments.

B. Corrections

In the **Federal Register** on August 21, 2015, in FR Doc. 2015–20638, on page 50877, at the bottom of the second column, in the last two sentences of the notice, which (1) discuss how to obtain telephone numbers to participate in conference calls, and (2) provide the Web site link to obtain public meeting document information, correct ''To receive the teleconference number and passcode for the September 3 meeting or for the October 6 conference call, call 301–415–6789 or email *YMEIS_Supplement@nrc.gov.* Meeting agendas and participation details will be available on the NRC's Public Meeting Schedule Web site at *http://www.nrc.gov/publicinvolve/publicmeetings/index.cfm* no later than 10 days prior to the meetings'' to read ''To receive the teleconference number and passcode for the September 3 meeting or for the October 15 conference call, call 301–415–6789 or email *YMEIS_Supplement@nrc.gov.* Meeting agendas and participation details will be available on the NRC's Public Meeting Schedule Web site at *http://meetings.nrc.gov/pmns/mtg* no later than 10 days prior to the meetings.''

III. Public Meetings

In addition to the public meetings announced previously, the NRC staff will hold another public meeting via teleconference to accept comments on the draft supplement on November 12, 2015, from 2:00 p.m. until 4:00 p.m. Eastern Time. The telephone number for this teleconference is 888–790–2936 and the passcode is 1715992. The same number and passcode should be used for the October 15, 2015, teleconference that was previously announced (see meeting information at *http://meetings.nrc.gov/pmns/mtg*).

This public teleconference will be transcribed. Persons interested in attending or presenting oral comments during this teleconference are encouraged to pre-register. Persons may pre-register to attend or present oral comments by calling 301–415–6789 or by emailing *YMEIS_Supplement@nrc.gov* no later than 3 days prior to the meeting. Individual oral comments may be limited by the time available, depending on the number of persons who register. If special equipment or accommodations are needed to attend or present information at a public meeting, the need should be brought to the NRC's attention no later than 10 days prior to the meeting to provide the NRC staff adequate notice to determine whether the request can be accommodated. The teleconference agenda and participation details will be available on the NRC's Public Meeting Schedule Web site at *http://meetings.nrc.gov/pmns/mtg* no later than 10 days prior to the meeting.

Dated at Rockville, Maryland, this 11th day of September 2015.

For the Nuclear Regulatory Commission.

Christine Pineda,

Senior Project Manager, Yucca Mountain Directorate, Office of Nuclear Material Safety and Safeguards.

[FR Doc. 2015–23510 Filed 9–17–15; 8:45 am]

BILLING CODE 7590–01–P

POSTAL REGULATORY COMMISSION

[Docket No. CP2015–137; Order No. 2705]

New Postal Product

AGENCY: Postal Regulatory Commission.

ACTION: Notice.

SUMMARY: The Commission is noticing a recent Postal Service filing concerning an additional Global Expedited Package Services 3 negotiated service agreement. This notice informs the public of the filing, invites public comment, and takes other administrative steps.

DATES: *Comments are due:* September 21, 2015.

ADDRESSES: Submit comments electronically via the Commission's Filing Online system at *http://www.prc.gov.* Those who cannot submit comments electronically should contact the person identified in the **FOR FURTHER INFORMATION CONTACT** section by telephone for advice on filing alternatives.

FOR FURTHER INFORMATION CONTACT: David A. Trissell, General Counsel, at 202–789–6820.

SUPPLEMENTARY INFORMATION:

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I. Introduction
II. Notice of Commission Action
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I. Introduction

On September 11, 2015, the Postal Service filed notice that it has entered into an additional Global Expedited Package Services 3 (GEPS 3) negotiated service agreement (Agreement).[1]

To support its Notice, the Postal Service filed a copy of the Agreement, a copy of the Governors' Decision authorizing the product, a certification of compliance with 39 U.S.C. 3633(a), and an application for non-public treatment of certain materials. It also filed supporting financial workpapers.

II. Notice of Commission Action

The Commission establishes Docket No. CP2015–137 for consideration of matters raised by the Notice.

The Commission invites comments on whether the Postal Service's filing is consistent with 39 U.S.C. 3632, 3633, or 3642, 39 CFR part 3015, and 39 CFR part 3020, subpart B. Comments are due no later than September 21, 2015. The public portions of the filing can be accessed via the Commission's Web site (*http://www.prc.gov*).

The Commission appoints Curtis E. Kidd to serve as Public Representative in this docket.

III. Ordering Paragraphs

It is ordered:

1. The Commission establishes Docket No. CP2015–137 for consideration of the matters raised by the Postal Service's Notice.

2. Pursuant to 39 U.S.C. 505, Curtis E. Kidd is appointed to serve as an officer of the Commission to represent the interests of the general public in this proceeding (Public Representative).

3. Comments are due no later than September 21, 2015.

4. The Secretary shall arrange for publication of this order in the **Federal Register**.

By the Commission.

Ruth Ann Abrams,

Acting Secretary.

[FR Doc. 2015–23431 Filed 9–17–15; 8:45 am]

BILLING CODE 7710–FW–P

[1] Notice of United States Postal Service of Filing a Functionally Equivalent Global Expedited Package Services 3 Negotiated Service Agreement and Application for Non-Public Treatment of Materials Filed Under Seal, September 11, 2015 (Notice).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75916; File No. SR–BOX–2015–31]

Self-Regulatory Organizations; BOX Options Exchange LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Adopt a Principles-Based Approach To Prohibit the Misuse of Material Nonpublic Information by Market Makers

September 14, 2015.

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 September 3, 2015, BOX Options Exchange LLC (the ''Exchange'') 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 self-regulatory organization. The Commission is publishing this notice to solicit comments on the proposed rule from interested persons.

I. Self-Regulatory Organization's Statement of the Terms of Substance of the Proposed Rule Change

The Exchange proposes to adopt a principles-based approach to prohibit the misuse of material nonpublic information by Market Makers by deleting BOX Rule 8090 (Limitation on Dealings). The text of the proposed rule change is available from the principal office of the Exchange, at the Commission's Public Reference Room and also on the Exchange's Internet Web site at *http://boxexchange.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 these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in Sections A, B, and C below, of the most significant aspects 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 adopt a principles-based approach to prohibit the misuse of material non-public information by Market Makers by deleting BOX Rule 8090 (Limitation on Dealing). In doing so, the Exchange would harmonize its rules governing BOX Participants and BOX Market Makers relating to protecting against the misuse of material, non-public information. The Exchange believes that BOX Rule 8090 is no longer necessary because all Market Makers are subject to the Exchange's general principles-based requirements governing the protection against the misuse of material, non-public information, pursuant to BOX Rule 3090 (Prevention of the Misuse of Material Nonpublic Information), which obviates the need for separately-prescribed requirements for a subset of market participants on the Exchange. Additionally, there is no separate regulatory purpose served by having separate rules for Market Makers. The Exchange notes that this proposed rule change will not decrease the protections against the misuse of material, non-public information; instead, it is designed to provide more flexibility to Option Participants. This is a competitive filing that is based on a proposal recently submitted by NYSE MKT LLC (''NYSE MKT'') and approved by the Commission.[3]

Background

The Exchange has two classes of registered Options Participants. Pursuant to BOX Rule 100(a)(4), the term ''Options Participant'' or ''Participant'' means a firm, or organization that is registered with the Exchange pursuant to the Rule 2000 Series (Participation) for purposes of participating in options trading on BOX as an ''Order Flow Provider'' or ''Market Maker''. Pursuant to Rule 100(a)(30) Market Maker means an Options Participant registered with the Exchange for the purpose of making markets in options contracts traded on the Exchange and that is vested with the rights and responsibilities specified in the Rule 8000 Series. All Market Makers are designated as specialists on the Exchange for all purposes under the Exchange Act or Rules thereunder.

[3] *See* Securities Exchange Act Release No. 75432 (July 13, 2015), 80 FR 42597 (July 17, 2015) (Order Approving SR–NYSEMKT–2015–23).

BOX Rule 8040 (Market Maker Obligations) specifies the obligations of Market Makers. The heightened quoting obligations of Market Makers are set forth in BOX Rule 8050 (Market Maker Quotations).[4] BOX Rule 8090 requires Market Makers to maintain information barriers that are reasonably designed to prevent the misuse of material, non-public corporate or markets information in the possession of persons on one side of the barrier to persons on the other side of the barrier.

Proposed Rule Change

The Exchange believes that the particularized guidelines in BOX Rule 8090 for Market Makers are no longer necessary and proposes to delete it. Rather, the Exchange believes that BOX Rule 3090 (Prevention of the Misuse of Material Nonpublic Information) governing the misuse of material, non-public information provides for an appropriate, principles-based approach to prevent the market abuses BOX Rule 8090 is designed to address. Specifically, BOX Rule 3090 requires every Options Participant to establish, maintain, and enforce written policies and procedures reasonably designed to prevent the misuse of material, non-public information by such Participant or persons associated with such Participant. For purposes of this requirement, the misuse of material, non-public information includes, but is not limited to, the following:

(1) Trading in any securities issued by a corporation, partnership, or a trust or similar entities, or in any related securities or related options or other derivative securities, or in any related non-U.S. currency, non-U.S. currency options, futures or options on futures on such currency, or any other derivatives based on such currency, or in any related commodity, related commodity futures or options on commodity futures or any other related commodity derivatives, while in possession of material nonpublic information concerning that issuer;

(2) trading in an underlying security or related options or other derivative securities, or in any related non-U.S. currency, non-U.S. currency options, futures or options on futures on such currency, or in any related commodity, related commodity futures or options on commodity futures or any other related commodity derivatives, or any other derivatives based on such currency, while in possession of material nonpublic information concerning imminent transactions in the above; and

(3) disclosing to another person any material nonpublic information involving a corporation, partnership, or Funds or a trust or similar entities whose shares are publicly traded or disclosing an imminent transaction in an underlying security or related securities or in the underlying non-U.S. currency or any related non-U.S. currency options, futures or options on futures on such currency, or in any related commodity, related commodity futures or options on commodity futures or any other related commodity derivatives, or any other derivatives based on such currency for the purpose of facilitating the possible misuse of such material nonpublic information.

Because Options Participants are already subject to the requirements of BOX Rule 3090, the Exchange does not believe that it is necessary to separately require specific limitations on Market Makers. Deleting BOX Rule 8090 and requirements for specific procedures would provide Market Makers with the flexibility to adapt their policies and procedures as appropriate to reflect changes to their business model, business activities, or the securities market in a manner similar to how Options Participants on the Exchange currently operate and consistent with BOX Rule 3090.

As noted above, Market Makers are distinguished under Exchange rules from other Options Participants only to the extent that Market Makers have heightened quiting [sic] obligations. However, none of these heightened obligations provides different or greater access to nonpublic information than any other Options Participant on the Exchange.[5]

Accordingly, because Market Makers do not have any trading advantages at the Exchange due to their market role, the Exchange believes that they should be subject to the same rules regarding the protection against the misuse of material non-public information, which in this case, is existing BOX Rule 3090.[6]

The Exchange notes that its proposed approach to use a principles-based approach to protecting against the misuse of material non-public information for all of its registered Options Participants is consistent with recently filed rule changes for NYSE MKT and approved rule changes for, NYSE Arca Equities, Inc. (''NYSE Arca''), BATS Exchange, Inc.'s (''BATS''), and New York Stock Exchange LLC (''NYSE'') rules governing cash equity market makers on those respective exchanges.[7] Except for prescribed rules relating to floor-based designated market makers on the NYSE, who have access to specified non-public trading information, each of these exchanges have moved to a principles-based approach to protecting against the misuse of material non- public information. In connection with approving those rule changes, the Commission found that, with adequate oversight by the exchanges of their members, eliminating prescriptive information barrier requirements should not reduce the effectiveness of exchange rules requiring its members to establish and maintain systems to supervise the activities of its members, including written procedures reasonably designed to ensure compliance with applicable federal securities law and regulations, and with the rules of the applicable exchange.[8]

Comparable to members of cash equity markets, the Exchange believes that a principles-based rule applicable to members of options markets would be equally effective in protecting against

[4] BOX Rule 8050(e), *Continuous Quotes,* On a daily basis, a Market Maker must during regular market hours make markets and enter into any resulting transactions consistent with the applicable quoting requirements specified in these rules, such that on a daily basis a Market Maker must post valid quotes at least sixty percent (60%) of the time that the classes are open for trading. These obligations will apply to all of the Market Maker's appointed classes collectively, rather than on a class-by-class basis.

[5] *See* BOX Rules 8040 and 8050.

[6] The Exchange notes that by deleting BOX Rule 8090, the Exchange would no longer require specific information barriers for Market Makers or require pre-approval of any information barriers that a Market Maker would erect for purposes of protecting against the misuse of material non-public information. However, as is the case today with Options Participants, information barriers of new entrants, would be subject to review as part of a new firm application. Moreover, the policies and procedures of Market Makers, including those relating to information barriers, would be subject to review by FINRA, on behalf of the Exchange, pursuant to a Regulatory Services Agreement.

[7] *See* Securities Exchange Act Release No. 75432 (July 13, 2015), 80 FR 42597 (July 17, 2015) (Order Approving Adopting a Principles-Based Approach to Prohibit the Misuse of Material Nonpublic Information by Specialists and e-Specialists by Deleting Rule 927.3NY and Section (f) of Rule 927.5NY). *See also* Securities Exchange Act Release Nos. 60604 (Sept. 2, 2009), 76 FR 46272 (Sept. 8, 2009) (SR–NYSEArca–2009–78) (Order approving elimination of NYSE Arca rule that required market makers to establish and maintain specifically prescribed information barriers, including discussion of NYSE Arca and Nasdaq rules) (''Arca Approval Order''); 61574 (Feb. 23, 2010), 75 FR 9455 (Mar. 2, 2010) (SR–BATS–2010–003) (Order approving amendments to BATS Rule 5.5 to move to a principles-based approach to protecting against the misuse of material, non-public information, and noting that the proposed change is consistent with the approaches of NYSE Arca and Nasdaq) (''BATS Approval Order''); and 72534 (July 3, 2014), 79 FR 39440 (July 10, 2014), SR–NYSE–2014–12) (Order approving amendments to NYSE Rule 98 governing designated market makers to move to a principles-based approach to prohibit the misuse of material non-public information) (''NYSE Approval Order'').

[8] *See, e.g.,* BATS Approval Order, *supra* note 7 at 9458.

the misuse of material non-public information. Indeed, BOX Rule 3090 is currently applicable to Options Participants which already requires policies and procedures reasonably designed to protect against the misuse of material nonpublic information, which is similar to the respective NYSE MKT, NYSE Arca Equities, BATS and NYSE rules governing cash equity market makers. The Exchange believes BOX Rule 3090 provides appropriate protection against the misuse of material nonpublic information by Options Participants and there is no longer a need for prescriptive information barrier requirements in BOX Rule 8090.

The Exchange notes that even with this proposed rule change, pursuant to BOX Rule 3090, an Options Participant would still be obligated to ensure that its policies and procedures reflect the current state of its business and continue to be reasonably designed to achieve compliance with applicable federal securities law and regulations, including Section 15(g) of the Act,[9] and with applicable Exchange rules, including being reasonably designed to protect against the misuse of material, non-public information. While information barriers would not specifically be required under the proposal, BOX Rule 3090 already requires that an Options Participant consider its business model or business activities in structuring its policies and procedures, which may dictate that an information barrier or a functional separation be part of the appropriate set of policies and procedures that would be reasonably designed to achieve compliance with applicable securities law and regulations, and with applicable Exchange rules.

The Exchange believes that the proposed reliance on the principles-based BOX Rule 3090 would ensure that an Options Participant would be required to protect against the misuse of any material non-public information. As noted above, BOX Rule 3090 already requires that firms refrain from trading while in possession of material non-public information concerning imminent transactions in the security or related product. The Exchange believes that moving to a principles-based approach rather than prescribing how and when to wall off a Market Maker from the rest of the firm would provide Market Makers with flexibility when managing risk across a firm, including integrating options positions with other positions of the firm or, as applicable, by the respective independent trading unit.

[9] 15 U.S.C. 78o(g).

2. Statutory Basis

The Exchange believes that the proposal is consistent with the requirements of Section 6(b) of the Securities Exchange Act of 1934 (the ''Act''),[10] in general, and Section 6(b)(5) of the Act,[11] in particular, in that it is designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in facilitating transactions in securities, 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.

The Exchange believes that the proposed rule change would remove impediments to and perfect the mechanism of a free and open market by adopting a principles- based approach to permit an Options Participant to maintain and enforce policies and procedures to, among other things, prohibit the misuse of material non-public information and provide flexibility on how a Market Maker structures its operations. The Exchange notes that the proposed rule change is based on an approved rule of the Exchange to which Options Participants—BOX Rule 3090—and harmonizes the rules governing Options Participants. Moreover, Market Makers would continue to be subject to federal and Exchange requirements for protecting material non- public order information.[12] The Exchange believes that the proposed rule change would remove impediments to and perfect the mechanism of a free and open market because it would harmonize the Exchange's approach to protecting against the misuse of material nonpublic information and no longer subject Market Makers to prescriptive requirements. The Exchange does not believe that the existing prescriptive requirements applicable to Options Participants are narrowly tailored to their respective roles because neither market participant has access to Exchange trading information in a manner different from any other market participant on the Exchange.

The Exchange further believes the proposal is designed to prevent fraudulent and manipulative acts and practices and to promote just and equitable principles of trade because existing rules make clear to Options Participants the type of conduct that is prohibited by the Exchange. While the proposal eliminates prescriptive requirements relating to the misuse of material non-public information, Market Makers would remain subject to existing Exchange rules requiring them to establish and maintain systems to supervise their activities, and to create, implement, and maintain written procedures that are reasonably designed to comply with applicable securities laws and Exchange rules, including the prohibition on the misuse of material, nonpublic information. Additionally, the policies and procedures of Market Makers, including those relating to information barriers, would be subject to review by FINRA, on behalf of the Exchange.[13]

[10] 15 U.S.C. 78f(b).

[11] 15 U.S.C. 78f(b)(5).

[12] *See* 15 U.S.C. 78o(g) and BOX Rule 3090.

The Exchange notes that the proposed rule change would still require that Market Makers maintain and enforce policies and procedures reasonably designed to ensure compliance with applicable federal securities laws and regulations and with Exchange rules. Even though there would no longer be pre-approval of Market Maker information barriers, any Market Maker written policies and procedures would continue to be subject to oversight by the Exchange and therefore the elimination of prescribed restrictions should not reduce the effectiveness of the Exchange rules to protect against the misuse of material non-public information. Rather, Options Participants will be able to utilize a flexible, principles-based approach to modify their policies and procedures as appropriate to reflect changes to their business model, business activities, or to the securities market itself. Moreover, while specified information barriers may no longer be required, an Options Participant's business model or business activities may dictate that an information barrier or functional separation be part of the appropriate set of policies and procedures that would be reasonably designed to achieve compliance with applicable securities laws and regulations, and with applicable Exchange rules. The Exchange therefore believes that the proposed rule change will maintain the existing protection of investors and the public interest that is currently applicable to Market Makers, while at the same time removing impediments to and perfecting a free and open market by moving to a principles-based approach to protect against the misuse of material non-public information.

[13] *See supra,* note 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 not necessary or appropriate in furtherance of the purposes of the Act. In this regard and as indicated above, the Exchange notes that the rule change is being proposed as a competitive response to a filing submitted by NYSE MKT that was recently approved by the Commission.[14]

To the contrary, the Exchange believes that the proposal will enhance competition by allowing Market Makers to comply with applicable Exchange rules in a manner best suited to their business models, business activities, and the securities markets, thus reducing regulatory burdens while still ensuring compliance with applicable securities laws and regulations and Exchange rules. The Exchange believes that the proposal will foster a fair and orderly marketplace without being overly burdensome upon Market Makers.

Moreover, the Exchange believes that the proposed rule change would eliminate a burden on competition for Options Participants which currently exists as a result of disparate rule treatment between the options and equities markets regarding how to protect against the misuse of material non-public information. For those Options Participants that are also members of equity exchanges, their respective equity market maker operations are now subject to a principles-based approach to protecting against the misuse of material non-public information. The Exchange believes it would remove a burden on competition to enable Options Participants to similarly apply a principles-based approach to protecting against the misuse of material nonpublic information in the options space. To this end, the Exchange notes that BOX Rule 3090 still requires Market Makers to evaluate its business to assure that its policies and procedures are reasonably designed to protect against the misuse of material nonpublic information. However, with this proposed rule change, an Options Participant that trades equities and options could look at its firm more holistically to structure its operations in a manner that provides it with better tools to manage its risks across multiple security classes, while at the same time protecting against the misuse of material non-public information.

[14] *See supra,* note 3.

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 comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The Exchange believes that the foregoing proposed rule change may take effect upon filing with the Commission pursuant to Section 19(b)(3)(A) of the Act and Rule 19b–4(f)(6) thereunder 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 its filing date, or such shorter time as the Commission may designate.

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: (i) Necessary or appropriate in the public interest; (ii) for the protection of investors; or (iii) otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or 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–BOX–2015–31 on the subject line.

Paper Comments

• Send paper comments in triplicate to Brent J. Fields, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BOX–2015–31. 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 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 Number SR–BOX–2015–31 and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[15]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23400 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

[15] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

Proposed Collection; Comment Request

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE., Washington, DC 20549–2736

Extension:

Interactive Data; SEC File No. 270–330, OMB Control No. 3235–0645

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') is soliciting comments on the collection of information summarized below. The Commission plans to submit this existing collection of information to the Office of Management and Budget for extension and approval.

The ''Interactive Data'' collection of information requires issuers filing registration statements under the Securities Act of 1933 (15 U.S.C. 77a *et seq.*) and reports under the Securities Exchange Act of 1934 (15 U.S.C. 78a *et seq.*) to submit specified financial information to the Commission and post it on their corporate Web sites, if any, in interactive data format using eXtensible Business Reporting Language (XBRL). This collection of information is located primarily in registration statement and report exhibit provisions, which require interactive data, and Rule 405 of Regulation S–T (17 CFR 232.405), which specifies how to submit and post interactive data. The exhibit provisions are in Item 601(b)(101) of Regulation S–K (17 CFR 229.601(b)(101), F–10 under the Securities Act (17 CFR 239.40) and Forms 20–F, 40–F and 6–K under the Exchange Act (17 CFR 249.220f, 17 CFR 249.240f and 17 CFR 249.306).

In interactive data format, financial statement information could be downloaded directly into spreedsheets and analyzed in a variety of ways using commercial off-the-shelf software. The specified financial information already is and will continue to be required to be submitted to the Commission in traditional format under existing requirements. The purpose of the interactive data requirement is to make financial information easier for investors to analyze and assist issuers in automating regulatory filings and business information processing. We estimate that 10,229 respondents per year will each submit an average of 4.5 reponses per year for an estimated total of 46,031 responses. We further estimate an internal burden of 59 hours per response for a total annual internal burden of 2,715,829 hours (59 hours per response × 46,031 responses).

Written comments are invited on: (a) Whether this proposed 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 the burden imposed by the collection of information; (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 respondents, including through the use of automated collection techniques or other forms of information technology. Consideration will be given to comments and suggestions submitted in writing within 60 days of this publication.

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 control number.

Please direct your written comment to Pamela Dyson, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 100 F Street NE., Washington, DC 20549 or send an email to: *PRA_Mailbox@sec.gov.*

Dated: September 15, 2015.

Brent J. Fields,

Secretary.

[FR Doc. 2015–23465 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE., Washington, DC 20549–2736

Extension:

Regulation 14C (Commission Rules 14c–1 through 14c–7 and Schedule 14C) SEC File No. 270–057, OMB Control No. 3235–0057

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') has submitted to the Office of Management and Budget this request for extension of the previously approved collection of information discussed below.

Section 14(c) of the Securities Exchange Act of 1934 (the ''Exchange Act'') operates to require issuers that do not solicit proxies or consents from any or all of the holders of record of a class of securities registered under Section 12 of the Exchange Act and in accordance with the rules and regulations prescribed under Section 14(a) in connection with a meeting of security holders (including action by consent) to distribute to any holders that were not solicited an information statement substantially equivalent to the information that would be required to be transmitted if a proxy or consent solicitation were made. Regulation 14C (Exchange Act Rules 14c–1 through 14c–7 and Schedule 14C) (17 CFR 240.14c–1 through 240.14c–7 and 240.14c–101) sets forth the requirements for the dissemination, content and filing of the information statement. We estimate that Schedule 14C takes approximately 130.95 hours per response and will be filed by approximately 569 issuers annually. In addition, we estimate that 75% of the 130.95 hours per response (98.21 hours) is prepared by the issuer for an annual reporting burden of 55,881 hours (98.21 hours per response × 569 responses).

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 control number.

The public may view the background documentation for this information collection at the following Web site, *www.reginfo.gov* . Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503, or by sending an email to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Pamela Dyson, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 100 F Street NE., Washington, DC 20549 or send an email to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: September 15, 2015.

Brent J. Fields,

Secretary.

[FR Doc. 2015–23467 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

Submission for OMB Review; Comment Request

Upon Written Request Copies Available From: Securities and Exchange Commission, Office of FOIA Services, 100 F Street NE., Washington, DC 20549–2736

Extension:

Regulation 14A (Commission Rules 14a–1 through 14a–21 and Schedule 14A) SEC File No. 270–056, OMB Control No. 3235–0059.

Notice is hereby given that, pursuant to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*), the Securities and Exchange Commission (''Commission'') has submitted to the Office of Management and Budget this request for extension of the previously approved collection of information discussed below.

Section 14(a) of the Securities Exchange Act of 1934 (the ''Exchange Act'') operates to make it unlawful for a company with a class of securities registered pursuant to Section 12 of the Exchange Act to solicit proxies in contravention of such rules and regulations as the Commission has prescribed as necessary or appropriate in the public interest or for the protection of investors. The Commission has promulgated Regulation 14A to regulate the solicitation of proxies or consents. Regulation 14A (Exchange Act Rules 14a–1 through 14a–21 and Schedule 14A) (17 CFR 240.14a–1 through 240.14a–21 and 240.14a–101) sets forth the requirements for the dissemination, content and filing of proxy or consent solicitation materials in connection with annual or other meetings of holders of a Section 12-registered class of securities. We estimate that Schedule 14A takes approximately 130.52 hours per response and will be filed by approximately 5,586 issuers annually. In addition, we estimate that 75% of the 130.52 hours per response (97.89 hours) is prepared by the issuer for an annual reporting burden of 546,814 hours (97.89 hours per response × 5,586 responses).

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 control number.

The public may view the background documentation for this information collection at the following Web site, *www.reginfo.gov.* Comments should be directed to: (i) Desk Officer for the Securities and Exchange Commission, Office of Information and Regulatory Affairs, Office of Management and Budget, Room 10102, New Executive Office Building, Washington, DC 20503, or by sending an email to: *Shagufta_Ahmed@omb.eop.gov;* and (ii) Pamela Dyson, Director/Chief Information Officer, Securities and Exchange Commission, c/o Remi Pavlik-Simon, 100 F Street NE., Washington, DC 20549 or send an email to: *PRA_Mailbox@sec.gov.* Comments must be submitted to OMB within 30 days of this notice.

Dated: September 15, 2015.

Brent J. Fields,

Secretary.

[FR Doc. 2015–23466 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75915; File No. SR–BATS–2015–71]

Self-Regulatory Organizations; BATS Exchange, Inc.; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Related to Fees for Use of BATS Exchange, Inc.

September 14, 2015.

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 September 2, 2015, BATS Exchange, Inc. (the ''Exchange'' or ''BATS'') 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 Exchange has designated the proposed rule change as one establishing or changing a member due, fee, or other charge imposed by the Exchange under Section 19(b)(3)(A)(ii) of the Act[3] and Rule 19b–4(f)(2) thereunder,[4] which renders the proposed rule change effective upon filing with the Commission. 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 filed a proposal to amend the fee schedule applicable to Members[5] and non-members of the Exchange pursuant to BATS Rules 15.1(a) and (c).

The text of the proposed rule change is available at the Exchange's Web site at *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 Statutory Basis for, the Proposed Rule Change

1. Purpose

The Exchange proposes to modify the ''Options Pricing'' section of its fee schedule effective immediately, in order to: (i) Modify pricing charged by the Exchange's options platform (''BATS Options'') including for orders routed away from the Exchange and executed at various away options exchanges; (ii) amend the thresholds related to meeting certain pricing tiers and to increase the rebate associated with such tiers; (iii) amend the fee for Customer[6] orders that remove liquidity in Penny Pilot Securities;[7] and (iv) make two non-substantive clean up changes.

Routing Fees

The Exchange currently charges the following rates for orders routed to certain other options exchanges: (i) Customer orders routed to C2 Options Exchange, Incorporated (''C2''), which yield the fee code 2C, are charged $0.47 per contract; (ii) non-Customer orders routed to C2, which yield fee code 2F, are charged $0.95 per contract; (iii) Customer orders in Penny Pilot Securities routed to NYSE Arca, Inc. (''Arca''), which yield fee code AC, are charged $0.52 per contract; and (iv) Customer orders in Penny Pilot Securities routed to Nasdaq Options Market LLC (''NOM''), which yield fee code QC, are charged $0.52 per contract. In an effort to continue to offer routing services to its Members at prices that approximate the cost to the Exchange, BATS Options is proposing to amend those rates as follows: (i) The fee for Customer orders routed to C2 and any Customer orders in Penny Pilot Securities routed to Arca or NOM (fee codes 2C, AC, and QC, respectively) would be increased to $0.70 per contract; and (ii) the fee for non-Customer orders routed to C2 (fee code 2F) would be reduced to $0.72 per contract.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] 15 U.S.C. 78s(b)(3)(A)(ii).

[4] 17 CFR 240.19b–4(f)(2).

[5] The term ''Member'' is defined as ''any registered broker or dealer that has been admitted to membership in the Exchange.'' *See* Exchange Rule 1.5(n).

[6] ''Customer'' applies to any transaction identified by a Member for clearing in the Customer range at the OCC, excluding any transaction for a Broker Dealer or a ''Professional'' as defined in Exchange Rule 16.1.

[7] ''Penny Pilot Securities'' are those issues quoted pursuant to Exchange Rule 21.5, Interpretation and Policy .01.

As noted previously and as set forth above, the Exchange's current approach to routing fees is to set forth in a simple manner certain sub-categories of fees that approximate the cost of routing to other options exchanges based on the cost of transaction fees assessed by each venue as well as costs to the Exchange for routing (*i.e.*, clearing fees, connectivity and other infrastructure costs, membership fees, etc.) (collectively, ''Routing Costs''). The Exchange then monitors the fees charged as compared to the costs of its routing services and adjusts its routing fees and/or sub-categories to ensure that the Exchange's fees do indeed result in a rough approximation of overall Routing Costs, and are not significantly higher or lower in any area. In performing this analysis, the Exchange has concluded that certain orders that it was routing to other options exchanges were costing more than it was charging, and in one case, were significantly less than it was charging. As a result, and in order to avoid subsidizing routing to away options exchanges and to continue providing quality routing services, the Exchange proposes relatively modest increases and adjustments to the charges assessed for the orders described above.

Tier Thresholds and Associated Rebate

The Exchange currently offers enhanced rebates under both the Firm, Broker Dealer, and Joint Back Office Penny Pilot Add Volume Tiers (which apply to fee code PF) and the Market Maker and Non-BATS Market Maker Penny Pilot Add Volume Tiers (which apply to fee code PM) to Members with trading activity on BATS Options that meets certain thresholds. More specifically, in Tier 3 of each of these sets of tiers, BATS Options offers enhanced rebates to orders that yield fee code PF and PM ($0.43 and $0.42, respectively) for Members that: (i) Have an ADAV [8] in Firm,[9] Broker Dealer,[10] and Joint Back Office [11] orders in Penny Pilot Securities (yielding Fee Code PF) equal to or greater than 0.35% of average TCV; and (ii) have an ADV [12] equal to or greater than 1.00% of average TCV.[13] The Exchange is proposing to amend the numerical thresholds associated with meeting these tiers by lowering the threshold for requirement (i) from 0.35% to 0.25% and increasing the threshold for requirement (ii) from 1.00% to 1.50%. Specifically, the Exchange is proposing that an order yielding fee code PF or PM will meet Tier 3 of the respective tiers where: (i) The Member has an ADAV in Firm, Broker Dealer, and Joint Back Office orders in Penny Pilot Securities (yielding Fee Code PF) equal to or greater than 0.25% of average TCV; and (ii) the Member has an ADV equal to or greater than 1.50% of average TCV. The Exchange is also proposing to increase the rebates for meeting these tiers to $0.47 per contract for fee code PF and PM, from $0.43 and $0.42 per contract, respectively.

Customer Orders in Non-Penny Pilot Securities

The Exchange currently charges $0.80 per contract for Customer orders that remove liquidity in non-Penny Pilot Securities. The Exchange is proposing to increase the fee to $0.84 per contract. The Exchange notes that the proposed fee is lower than the fees charged on NOM for removing liquidity in non-Penny Pilot Securities ($0.85 per contract) and is generally in line with the pricing at other options exchanges.

Clean Up Changes

Finally, the Exchange is also proposing to make two non-substantive clean up changes to its fee schedule. Specifically, the Exchange is proposing to capitalize the ''O'' in ''Joint Back office'' as it appears in the definition for ''Firm'' and to add a bullet in front of the definition of ''Penny Pilot Securities'' in order to make the formatting consistent with that of the other definitions in the fee schedule.

Implementation Date

The Exchange proposes to implement these amendments to its Fee Schedule effectively immediately.

2. Statutory Basis

The Exchange believes 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 of the Act.[14] Specifically, the Exchange believes that the proposed rule change is consistent with Section 6(b)(4) of the Act,[15] in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and other persons using any facility or system which the Exchange operates or controls. The Exchange notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues or providers of routing services if they deem fee levels to be excessive.

As explained above, the Exchange generally attempts to approximate the cost of routing to other options exchanges, including other applicable costs to the Exchange for routing. The Exchange believes that a pricing model based on approximate Routing Costs is a reasonable, fair and equitable approach to pricing. Specifically, the Exchange believes that its proposal to modify fees is fair, equitable and reasonable because the fees are generally an approximation of the cost to the Exchange for routing orders to such exchanges and the Exchange has concluded that certain orders that it was routing to other options exchanges were costing more than it was charging, and in one case, were costing significantly less than it was charging. Further to this point, the Exchange notes that it is proposing to decrease fees for non-Customer orders routed to C2. Accordingly, the Exchange believes that the proposed increases are fair, equitable and reasonable because they will help the Exchange to avoid subsidizing routing to away options exchanges and to continue providing quality routing services. The Exchange believes that its fee structure for orders routed to various venues is a fair and equitable approach to pricing, as it provides certainty with respect to execution fees at away options exchanges. Under its straightforward fee structure, taking all costs to the Exchange into account, the Exchange may operate at a slight gain or slight loss for orders routed to and executed at away options exchanges. As a general matter, the Exchange believes that the proposed fees will allow it to recoup and cover its costs of providing routing services to such exchanges. The Exchange notes that routing through the Exchange is voluntary. The Exchange

[8] ''ADAV'' means average daily added volume calculated as the number of contracts per day.

[9] ''Firm'' applies to any transaction identified by a Member for clearing in the Firm range at the Options Clearing Corporation (''OCC''), excluding any Joint Back office transaction.

[10] ''Broker Dealer'' applies to any order for the account of a broker dealer, including a foreign broker dealer, that clears in the Customer range at the OCC.

[11] ''Joint Back Office'' applies to any transaction identified by a Member for clearing in the Firm Range at the OCC that is identified with an origin code as Joint Back Office. A Joint Back Office participant is a Member that maintains a Joint Back Office arrangement with a clearing broker-dealer.

[12] ''ADV'' means average daily volume calculated as the number of contracts added or removed, combined, per day.

[13] ''TCV'' means total consolidated volume calculated as the volume reported by all exchanges to the consolidated transaction reporting plan for the month for which the fees apply, excluding volume on any day that the Exchange experiences an Exchange System Disruption and on any day with a scheduled early market close.

[14] 15 U.S.C. 78f.

[15] 15 U.S.C. 78f(b)(4).

also believes that the proposed fee structure for orders routed to and executed at these away options exchanges is fair and equitable and not unreasonably discriminatory in that it applies equally to all Members.

The Exchange reiterates that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if they deem fee levels to be excessive or providers of routing services if they deem fee levels to be excessive. Finally, the Exchange notes that it constantly evaluates its routing fees, including profit and loss attributable to routing, as applicable, in connection with the operation of a flat fee routing service, and would consider future adjustments to the proposed pricing structure to the extent it was recouping a significant profit or loss from routing to away options exchanges.

The Exchange also believes that the proposed amendments to the fee schedule related to the thresholds required to meet Tier 3 of both the Firm, Broker Dealer, and Joint Back Office Penny Pilot Add Volume Tiers and the Market Maker and Non-BATS Market Maker Penny Pilot Add Volume Tiers and the increased rebate of $0.47 per contract for achieving such tiers is a reasonable, fair and equitable, and not unfairly discriminatory allocation of fees and rebates because it will encourage greater participation on BATS Options, which, as described above the Exchange believes will result in higher levels of liquidity provision and introduction of higher volumes of orders into the price and volume discovery processes, which will benefit all participants on BATS Options. Specifically, the Exchange believes that the reduction in the threshold for a Member's ADAV in Penny Pilot Securities that yield fee code PF from 0.35% of average TCV and the increased threshold for a Member's ADV of average TCV from 1.00% to 1.50% combined with the increased rebate for meeting the thresholds is a reasonable, fair and equitable, and not unfairly discriminatory allocation of fees and rebates because, in conjunction, they will provide Members with a reasonably achievable threshold for receiving a greater rebate than they do today while simultaneously encouraging and rewarding higher levels of participation on the Exchange. By lowering the requirement for Firm, Broker Dealer, and Joint Back Office orders in Penny Pilot securities, increasing the requirement for ADV as a percentage of TCV, and increasing the rebate for achieving such tiers, the proposed amendment will encourage greater general participation on the Exchange, which will result in higher levels of liquidity provision and introduction of higher volumes of orders into the price and volume discovery processes, which will benefit all participants on BATS Options.

The Exchange believes the proposed increase of the standard fees for Customer orders that remove liquidity in non-Penny Pilot Securities (from $0.80 per contract to $0.84 per contract) is a reasonable, fair and equitable, and not unfairly discriminatory allocation of fees and rebates because the additional revenue generated through the increased fees will allow the Exchange to continue to offer competitive pricing and incentives for other types of orders, which will result in better market quality for all participants. Further, as noted above, the proposed standard fee is still lower than the standard fee offered by NOM for of $0.85 per contract.

The Exchange also believes that the proposed non-substantive changes to the definition of Firm and adding of the bullet to definition of Penny Pilot Securities are reasonable, fair, and equitable because they are designed to make the fee schedule easier to read and understand. The Exchange notes that neither of the proposed changes are designed to amend any fee or rebate, nor alter the manner in which the Exchange assess fees and rebates. These non-substantive changes to the fee schedule are intended to make the fee schedule clearer and less confusing for investors and eliminate potential investor confusion, thereby removing impediments to and perfecting the mechanism of a free and open market and a national market system, and, in general, protecting investors and the public interest.

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. As it relates to the proposed changes to routing fees, the proposed changes will assist the Exchange in recouping costs for routing orders to other options exchanges on behalf of its participants in a manner that is a better approximation of actual costs than is currently in place and that reflects pricing changes by various options exchanges as well as increases to other Routing Costs incurred by the Exchange. The Exchange also notes that Members may choose to mark their orders as ineligible for routing to avoid incurring routing fees.[16]

With respect to the proposed changes to the thresholds in the Firm, Broker Dealer, and Joint Back Office Penny Pilot Add Volume Tiers and the Market Maker and Non-BATS Market Maker Penny Pilot Add Volume Tiers and the increased rebates associated therewith, the Exchange does not believe that any such changes burden competition, but instead, that they enhance competition as they are intended to increase the competitiveness of and draw additional volume to BATS Options.

Finally, with respect to the change in fees for Customer orders that remove liquidity in non-Penny Pilot Securities, the Exchange does not believe that such change burdens competition, but instead, that it enhances competition as the proposed new pricing remains generally in line with that of other options exchanges and would still be lower than the per contract fee for an identical transaction that occurred on NOM.

As stated above, the Exchange notes that it operates in a highly competitive market in which market participants can readily direct order flow to competing venues if they deem fee levels to be excessive or providers of routing services if they deem routing fee levels to be excessive.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) of the Act[17] and paragraph (f)(2) of Rule 19b–4 thereunder.[18] 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. If the

[16] *See* BATS Rule 21.1(d)(8) (describing ''BATS Only'' orders for BATS Options) and BATS Rule 21.9(a)(1) (describing the BATS Options routing process, which requires orders to be designated as available for routing).

[17] 15 U.S.C. 78s(b)(3)(A).

[18] 17 CFR 240.19b–4(f)(2).

Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or 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–BATS–2015–71 on the subject line.

Paper Comments

• Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–BATS–2015–71. 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 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 Number SR–BATS–2015–71 and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[19]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23399 Filed 9–17–15; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75910; File No. SR–NASDAQ–2015–102]

Self-Regulatory Organizations; The NASDAQ Stock Market LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend Transaction Fees at Chapter XV, Section 2 Entitled ''NASDAQ Options Market—Fees and Rebates''

September 14, 2015.

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 September 1, 2015, 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, 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 transaction fees at Chapter XV, Section 2 entitled ''NASDAQ Options Market—Fees and Rebates,'' which governs pricing for NASDAQ members using the NASDAQ Options Market (''NOM''), NASDAQ's facility for executing and routing standardized equity and index options.

While these amendments are effective upon filing, the Exchange has designated the proposed amendments to be operative on September 1, 2015.

The text of the proposed rule change is available on the Exchange's Web site at *http://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 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 aspects 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 the following five [sic] changes to the NOM transaction fees set forth at Chapter XV, Section 2 for executing and routing standardized equity and index options under the Penny Pilot options program. The Penny Pilot was established in March 2008 and has since been expanded and extended through June 30, 2016.[3]

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[19] 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 Nos. 57579 (March 28, 2008), 73 FR 18587 (April 4, 2008) (SR–NASDAQ–2008–026) (notice of filing and immediate effectiveness establishing Penny Pilot); 60874 (October 23, 2009), 74 FR 56682 (November 2, 2009) (SR–NASDAQ–2009–091) (notice of filing and immediate effectiveness expanding and extending Penny Pilot); 60965 (November 9, 2009), 74 FR 59292 (November 17, 2009) (SR–NASDAQ–2009–097) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 61455 (February 1, 2010), 75 FR 6239 (February 8, 2010) (SR–NASDAQ–2010–013) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 62029 (May 4, 2010), 75 FR 25895 (May 10, 2010) (SR–NASDAQ–2010–053) (notice of filing and immediate effectiveness adding seventy-five classes to Penny Pilot); 65969 (December 15, 2011), 76 FR 79268 (December 21, 2011) (SR–NASDAQ–2011–169) (notice of filing and immediate effectiveness extension and replacement of Penny Pilot); 67325 (June 29, 2012), 77 FR 40127 (July 6, 2012) (SR–NASDAQ–2012–075) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through December 31, 2012); 68519 (December 21, 2012), 78 FR 136 (January 2, 2013) (SR–NASDAQ–2012–143) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through June 30, 2013); 69787 (June 18, 2013), 78 FR 37858 (June 24, 2013) (SR–NASDAQ–2013–082) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through December 31, 2013); 71105 (December 17, 2013), 78 FR 77530 (December 23, 2013) (SR–NASDAQ–2013–154) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through June 30, 2014); 79 FR 31151 (May 23, 2014), 79 FR 31151 (May 30, 2014) (SR–NASDAQ–2014–056) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through

Continued

The proposed changes are as follows:

Rebate to Add Liquidity in Penny Pilot Options: the Exchange proposes to

1. Increase the rebates to Participants that qualify for Tiers 8 of the Customer [4] and Professional [5] rebate program and that add greater than 1.40 percent of total Customer interest for the month.

Fee for Removing Liquidity in Penny Pilot Options: the Exchange proposes to:

2. Increase fees from $0.50 to $0.54 per contract for all Participant categories other than Customer, which remains at $0.48. Fees for removing liquidity in SPY [6] will remain unchanged by this proposal.

3. Increase the fee for removing liquidity for Participants that qualify for Tiers 7 and 8 of the Customer and Professional rebate program.

Each specific change is described in greater detail below.

Change 1

The Exchange is proposing to increase the rebates paid for providing Customer and Professional liquidity in Penny Pilot options. Currently, the Exchange offers eight volume-based rebate Tiers for Participants providing Customer or Professional liquidity in Penny Pilot options. These rebates range from $0.20 (Tier 1) to $0.48 (Tier 8) per contract depending upon the level of liquidity provided. Tiers 1 through 4 are based on Participants adding Customer, Professional, Firm, Non-NOM Market Maker and/or Broker-Dealer liquidity in Penny Pilot Options and/or Non-Penny Pilot Options as a percentage of total industry customer equity and ETF option ADV contracts per day in a month. Participants qualifying for Tiers 1 through 4 earn a rebate of $0.20 to $0.43 per contract. Tiers 5 through 7 add other, challenging volume-based requirements and offer rebates of $0.45 to $0.47 per contract of Customer or Professional liquidity provided in Penny Pilot options. Tiers 1 through 7 of the Customer or Professional rebate program will remain unchanged.

The Exchange is proposing to change only Tier 8 which currently offers a $0.48 rebate for executed Customer or Professional liquidity where:

> Participant adds Customer, Professional, Firm, Non-NOM Market Maker and/or Broker-Dealer liquidity in Penny Pilot Options and/or Non-Penny Pilot Options above 0.75% or more of total industry customer equity and ETF option ADV contracts per day in a month or Participant adds (1) Customer and/or Professional liquidity in Penny Pilot Options and/or Non-Penny Pilot Options of 30,000 or more contracts per day in a month, (2) the Participant has certified for the Investor Support Program set forth in Rule 7014, and (3) the Participant qualifies for rebates under the Qualified Market Maker (''QMM'') Program set forth in Rule 7014.

In addition, Participants that qualify for Tier 8 can get a supplemental rebate if they add:

> Customer, Professional, Firm, Non-NOM Market Maker and/or Broker-Dealer liquidity in Penny Pilot Options and/or Non- Penny Pilot Options of 1.15% or more of total industry customer equity and ETF option ADV contracts per day in a month will receive an additional $0.02 per contract Penny Pilot Options Customer Rebate to Add Liquidity for each transaction which adds liquidity in Penny Pilot Options in that month.

Participants that qualify for Tier 8 and the supplemental rebate receive a total rebate of $0.50 per contract of Customer liquidity provided in Penny Pilot options.

Beginning September 1, the Exchange is proposing to offer an increased supplemental rebate for certain Participants that qualify for Tier 8. Specifically, the Exchange proposes to offer an additional $0.05 rebate per contract for adding Customer liquidity in Penny Pilot Options in that month for Participants that add Customer, Professional, Firm, Non-NOM Market Maker and/or Broker-Dealer liquidity in Penny Pilot Options and/or Non- Penny Pilot Options of 1.40% or more of total industry customer equity and ETF option ADV contracts per day in a month. Participants that qualify for Tier 8 and the new supplemental rebate will receive a total rebate of $0.53 per contract of Customer liquidity executed in Penny Pilot options. This represents an increase of $0.03 per contract for Participants qualifying for this new supplemental rebate.

Change 2

The Exchange also proposes, beginning September 1, to increase from $0.50 to $0.54 per contract the fees assessed for removing liquidity in Penny Pilot options for all Participant categories other than Customer, which will remain unchanged at $0.48. This will represent an increase of $0.04 per contract of liquidity removed in the Professional, Firm, NOM Market Maker, Non-NOM Market Maker, and Broker Dealer categories for Participants that qualify for no fee reductions. For executions in SPY, the fees will remain unchanged by this proposal. Specially, the fees assessed for executions in SPY will remain $0.48 per contact for Customer and $0.50 per contract for all other Participants.

Change 3

The Exchange proposes to increase the fee assessed for removing liquidity for Participants that qualify for Tiers 7 and 8 of the Customer and Professional rebate program. As described above, the Exchange currently offers eight tiers of volume-based rebates for Participants that add Customer or Professional liquidity in Penny Pilot options. Relative to other Participants, Participants that qualify for Tiers 7 and 8 receive increased rebates for adding liquidity, and they also are assessed reduced fees for removing liquidity. Specifically, Participants that qualify for Customer or Professional Rebate to Add Liquidity Tiers 7 or 8 in a given month are assessed a Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer Fee for Removing Liquidity in Penny Pilot Options of $0.48 per contract and a Customer Fee for Removing Liquidity in Penny Pilot Options of $0.47 per contract. Participants that do not qualify for Tiers 7 and 8 currently pay $0.50 per contract for removing liquidity in the Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer categories, and $0.48 per contract for removing liquidity in the Customer category. In other words, this represents a relative reduction of $0.02 in the Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer categories, and a $0.01 relative reduction in the Customer liquidity category.

Beginning September 1, the Exchange proposes to charge these same Participants (those that qualify for Customer or Professional Rebate to Add Liquidity Tiers 7 or 8 in a given month) a fee of $0.50 for removing liquidity for Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-

December 31, 2014); 73686 (December 2, 2014), 79 FR 71477 (November 25, 2014) (SR–NASDAQ–2014–115) (notice of filing and immediate effectiveness and extension and replacement of Penny Pilot through June 30, 2015) and 75283 (June 24, 2015), 80 FR 37347 (June 30, 2015) (SR–NASDAQ–2015–063) (Notice of Filing and Immediate Effectiveness of a Proposed Rule Change Relating to Extension of the Exchange's Penny Pilot Program and Replacement of Penny Pilot Issues That Have Been Delisted.) *See also* NOM Rules, Chapter VI, Section 5.

[4] The term ''Customer'' refers to a customer in a transaction that is marked by a Participant in the Customer range for clearing purposes at The Options Clearing Corporation (''OCC''). Such a transaction is not for the account of a broker, dealer or ''Professional'' (see next footnote).

[5] The term ''Professional'' means any person or entity that (i) is not a broker or dealer in securities, and (ii) places more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s), *See* Chapter I, Section 1(a)(48). All Professional orders must be appropriately marked by Participants.

[6] SPDR® S&P 500® ETF Trust.

Dealer in Penny Pilot Options. As described above, also beginning September 1, Participants that do not qualify for Tiers 7 and 8 will pay $0.54 per contract for removing liquidity in the Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer categories, and $0.48 per contract for removing liquidity in the Customer category. As a result, beginning September 1, Participants that qualify for Tiers 7 and 8 will enjoy a relative fee reduction of $0.04 in the Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer categories, and will pay the same Customer fee for removing liquidity of $0.48 per contract as is the case for all other Participants.

2. Statutory Basis

NASDAQ believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[7] in general, and with Section 6(b)(4) and 6(b)(5) of the Act,[8] in particular, in that it provides for the equitable allocation of reasonable dues, fees and other charges among members and issuers and other persons using any facility or system which NASDAQ operates or controls, and is not designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

Change 1

The Exchange believes that it is an equitable allocation of reasonable fees to offer an additional $0.05 rebate per contract for adding Customer liquidity in Penny Pilot Options in that month for Participants that add Customer, Professional, Firm, Non-NOM Market Maker and/or Broker-Dealer liquidity in Penny Pilot Options and/or Non- Penny Pilot Options of 1.40% or more of total industry customer equity and ETF option ADV contracts per day in a month. As stated above, the use of volume-based rebate tiers is well accepted as consistent with an equitable allocation of reasonable fees under the Act. In fact, the Exchange's proposal represents only a minor extension of the rebate program that already exists on the Exchange: Participants that qualify for Tier 8 and the new supplemental rebate will receive a total rebate of $0.53 per contract of Customer liquidity executed in Penny Pilot options which is an increase of $0.03 per contract beyond the existing supplemental rebate of $0.02.

The Exchange's proposal to increase the supplemental rebate for providing Customer liquidity in Penny Pilot options is also equitable and not unfairly discriminatory under the Act. As stated above, the use of volume-based incentives has long been accepted as an equitable and not unfairly discriminatory pricing practice employed at multiple competing options exchanges. In fact, the specific volume-based incentive proposed here—a supplemental rebate for providing greater amounts of Customer liquidity in Penny Pilot options—is currently employed by NOM and it has been accepted as equitable and not unfairly discriminatory under the Act. As is true of the existing supplemental rebate, the proposed $0.03 additional supplement is a ''fair'' form of discrimination because it benefits all market Participants by attracting valuable liquidity to the market and thereby enhancing the trading quality and efficiency of all.

Change 2

It is also an equitable allocation of reasonable fees for the Exchange to increase from $0.50 to $0.54 per contract the fees assessed for removing liquidity in Penny Pilot options for all Participant categories other than Customer, while the rebate [sic] for Customer liquidity remains unchanged at $0.48. The increase of $0.04 per contract of liquidity removed in the Professional, Firm, NOM Market Maker, Non-NOM Market Maker, and Broker Dealer categories results in a maximum fee that is within the range of maximum fees at other exchanges Penny Pilot options that have been accepted as an equitable allocation of reasonable fees under the Act.[9] The total differential of $0.06 also is below the maximum differentials employed by other exchanges that have previously been and currently are accepted as equitable and reasonable under the Act. Finally, this proposed fee increase for removing liquidity must be read in conjunction with Change 1, which increase rebates for providing liquidity, when determining the overall equity and reasonableness of this proposed rule change.

The Exchange also believes that maintaining the current execution prices for SPY while raising fees for other options is consistent with an equitable allocation of reasonable fees and is not unfairly discriminatory. Multiple exchanges have adopted pricing for a select group of symbols, a practice that has been accepted as consistent with an equitable allocation of reasonable fees under the Act.[10] The unique nature of trading in SPY, the most actively traded standardized option in the U.S, justifies differentiating it from other symbols, particularly where that differentiation results in maintaining lower execution fees.

The Exchange's proposal is equitable and not unfairly discriminatory for many of the same reasons. It is common practice among options exchanges to differentiate between fees for removing Customer liquidity and fees for removing other categories of liquidity, and such differentiation has been accepted as not unfairly discriminatory under the Act. Charging lower fees for removing Customer liquidity has been considered beneficial in that attracting this liquidity benefits all market Participants by improving the overall quality of trading on the Exchange. The level of differentiation ($0.06) is also within the bounds of what has been accepted as not unfairly discriminatory under the Act. Finally, the proposed fees will be imposed equally within each category of liquidity removed among all Participants.

Change 3

It is an equitable allocation of reasonable fees for the Exchange to charge Participants that qualify for Customer or Professional Rebate to Add Liquidity Tiers 7 or 8 in a given month a fee of $0.50 (an increase from $0.48) for removing liquidity in Penny Pilot Options for Professional, Firm, Non-NOM Market Maker, NOM Market Maker or Broker-Dealer Fee and $0.48 (an increase from $0.47) for removing Customer liquidity. The total maximum fee for qualifying Participants will be $0.50, which is below the maximum fees assessed by other exchanges for similar executions. Moreover, the increase of $0.01 for the removal of liquidity in the Customer category and $0.02 for removing liquidity in all other categories is a modest increase in isolation, and even more so when read in conjunction with the proposed increased rebates for providing liquidity described above regarding Changes 1, 2, and 3. Finally, Participants that qualify for Tiers 7 and 8 and that pay this increased fee will actually enjoy a slightly higher differential of $0.04 as opposed to the current differentials of $0.01 and $0.02 relative to non-qualifying Participants.

[7] 15 U.S.C. 78f.

[8] 15 U.S.C. 78f(b)(4) and (5).

[9] For example, MIAX charges $0.55 for executions in the following penny pilot options: EEM, GLD, IWM, QQQ and SPY (*see* MIAX fee schedule). BOX assesses fees greater than $0.55 to Non-customers for executions in Penny Pilot options (*see* BOX Options fee schedule).

[10] *See, e.g.,* fee schedules of MIAX and CBOE (both CBOE and C2).

The Exchange's proposal is equitable and not unfairly discriminatory for many of the same reasons. It is common practice among options exchanges to differentiate between fees for removing Customer liquidity and fees for removing other categories of liquidity, and such differentiation has been accepted as not unfairly discriminatory under the Act. In fact, the NOM fee reductions for Participants qualifying for Tiers 7 and 8 of the Customer and Professional rebate program has existed and been accepted as consistent with the Act for some time. The level of differentiation created by this minor revision ($0.04) is within the bounds of what has been accepted as not unfairly discriminatory under the Act. Finally, the proposed fees will be imposed equally within each category of liquidity removed among all Participants.

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. The Exchange operates in a highly competitive market in which many sophisticated and knowledgeable market participants can readily and do send order flow to competing exchanges if they deem fee levels or rebate incentives at a particular exchange to be excessive or inadequate. Additionally, new competitors have entered the market and still others are reportedly entering the market shortly. These market forces ensure that the Exchange's fees and rebates remain competitive with the fee structures at other trading platforms. In that sense, the Exchange's proposal is actually pro-competitive because the Exchange is simply responding to competition by adjusting rebates and fees in order to remain competitive in the current environment.

Change 1

The Exchange does not believe that increasing the rebates to Participants that qualify for Tiers 8 of the Customer and Professional rebate program and that add greater than 1.40 percent of total Customer interest for the month places any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. As described above, the use of volume-based tiers has been accepted as consistent with the Act, including Tiers 1 through 8 of the existing Customer and Professional rebate program for Penny Pilot options. Volume-based fee reductions such as that proposed here are recognized by economists as a pro-competitive reflection of a competitive marketplace such as the SEC has fostered in the national market system for standardized options.

Additionally, the proposed change is pro-competitive because it encourages Participants to add more liquidity to the NOM market and thereby strengthen NOM's competitive position. Greater liquidity benefits all market participants by providing more trading opportunities and attracting greater participation by market makers. An increase in the activity of these market participants in turn facilitates tighter spreads. All Participants are eligible to participate in the Firm category if they choose, and each can thereby become eligible to earn the rebates by transacting the requisite volume.

Change 2

The Exchange does not believe that increase fees from $0.50 to $0.54 per contract for all Participant categories other than Customer, which remains at $0.48 places any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. In a competitive marketplace such as that for trading of standardized options, the Exchange is constrained from raising prices to super-competitive levels by the risk of losing out to better-priced competitors. The resulting fee of $0.54 is below fees charged by other Exchanges, which have themselves been considered consistent with the Act. In addition, the fee increase should be read in conjunction with increased rebates (lower fees) described above that offset the fee increase and that the Exchange believes are necessary and well-targeted to increase the overall competitiveness of the market.

The Exchange does not believe that maintaining existing fees for executions in SPY ($0.48 per contract for Customer liquidity and $0.50 for all other liquidity), which remains at $0.48 places any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. Rather, the Exchange believes that distinguishing between SPY and all other options is pro-competitive in that it reflects the unique nature of the fierce competition that exists in SPY as the most actively traded multiply listed option in the U.S. Multiple exchanges set prices that apply to a select group of symbols and those pricing programs have been accepted as consistent with the Act.[11]

[11] For example, MIAX charges $0.55 for executions in the following penny pilot options: EEM, GLD, IWM, QQQ and SPY (*see* MIAX fee schedule). *See also* CBOE and C2 fee schedules.

Change 3

The Exchange does not believe that increasing the fee for removing liquidity for Participants that qualify for Tiers 7 and 8 of the Customer and Professional rebate program places any burden on competition not necessary or appropriate in furtherance of the purposes of the Act. In a competitive marketplace such as that for trading of standardized options, the Exchange is constrained from raising prices to super-competitive levels by the risk of losing out to better-priced competitors. The fee increases of $0.02 or $0.01 are modest, and the resulting fees of $0.50 and $0.48 are below fees charged by other Exchanges, which have themselves been considered consistent with the Act. In addition, the fee increase should be read in conjunction with increased rebates (lower fees) described above that offset the fee increase and that the Exchange believes are necessary and well-targeted to increase the overall competitiveness of the market.

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

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act.[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: (i) Necessary or appropriate in the public interest; (ii) for the protection of investors; or (iii) otherwise in furtherance of the purposes of the Act. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or 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

[12] 15 U.S.C. 78s(b)(3)(A)(ii).

• Send an email to *rule-comments@sec.gov.* Please include File Number SR–NASDAQ–2015–102 on the subject line.

Paper Comments

• Send paper comments in triplicate to Brent J. Fields, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–NASDAQ–2015–102. 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–NASDAQ–2015–102 and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23396 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75917; File No. 4–631]

Joint Industry Plan; Notice of Filing of the Ninth Amendment to the National Market System Plan To Address Extraordinary Market Volatility by BATS Exchange, Inc., BATS Y-Exchange, Inc., Chicago Board Options Exchange, Inc., Chicago Stock Exchange, Inc., EDGA Exchange, Inc., EDGX Exchange, Inc., Financial Industry Regulatory Authority, Inc., NASDAQ OMX BX, Inc., NASDAQ OMX PHLX LLC, The Nasdaq Stock Market LLC, National Stock Exchange, Inc., New York Stock Exchange LLC, NYSE MKT LLC, and NYSE Arca, Inc.

September 14, 2015.

I. Introduction

On July 31, 2015, the New York Stock Exchange LLC (''NYSE''), on behalf of the following parties to the National Market System Plan to Address Extraordinary Market Volatility (the ''Plan''): [1] BATS Exchange, Inc., BATS Y-Exchange, Inc., Chicago Board Options Exchange, Incorporated (''CBOE''), Chicago Stock Exchange, Inc., EDGA Exchange, Inc., EDGX Exchange, Inc., Financial Industry Regulatory Authority, Inc., NASDAQ OMX BX, Inc., NASDAQ OMX PHLX LLC, the Nasdaq Stock Market LLC, and National Stock Exchange, Inc., NYSE MKT LLC, and NYSE Arca, Inc. (collectively with the NYSE, the ''Participants''), filed with the Securities and Exchange Commission (''Commission'') pursuant to Section 11A of the Securities Exchange Act of 1934 (''Act'') [2] and Rule 608 thereunder,[3] a proposal to amend the Plan.[4] The proposal reflects changes unanimously approved by the Participants. The Amendment to the Plan proposes to extend the pilot period of the Plan from October 23, 2015 to April 22, 2016. A copy of the Plan, as proposed to be amended is attached as Exhibit A hereto. The Commission is publishing this notice to solicit comments from interested persons on the Amendment to the Plan.[5]

II. Description of the Plan

Set forth in this Section II is the statement of the purpose and summary of the Amendment, along with the information required by Rule 608(a)(4) and (5) under the Exchange Act,[6] prepared and submitted by the Participants to the Commission.[7]

A. Statement of Purpose and Summary of the Plan Amendment

The Participants filed the Plan on April 5, 2011, to create a market-wide limit up-limit down mechanism intended to address extraordinary market volatility in NMS Stocks, as defined in Rule 600(b)(47) of Regulation NMS under the Exchange Act. The Plan sets forth procedures that provide for market-wide limit up-limit down requirements that would prevent trades in individual NMS Stocks from occurring outside of the specified price bands. These limit up-limit down requirements are coupled with Trading Pauses, as defined in Section I(Y) of the Plan, to accommodate more fundamental price moves. In particular, the Participants adopted this Plan to address the type of sudden price movements that the market experienced on the afternoon of May 6, 2010.

As set forth in more detail in the Plan, all trading centers in NMS Stocks, including both those operated by Participants and those operated by members of Participants, shall establish, maintain, and enforce written policies and procedures that are reasonably designed to comply with the limit up-limit down requirements specified in the Plan. More specifically, the single plan processor responsible for consolidation of information for an NMS Stock pursuant to Rule 603(b) of Regulation NMS under the Exchange Act will be responsible for calculating

[1] On May 31, 2012, the Commission approved the Plan, as modified by Amendment No. 1. *See* Securities Exchange Act Release No. 67091, 77 FR 33498 (Jun. 6, 2012) (File No. 4–631). On February 26, 2013, the Commission published for immediate effectiveness the Second Amendment to the Plan. *See* Securities Exchange Act Release No. 68953 (Feb. 20, 2013), 78 FR 13113. On April 3, 2013, the Commission approved the Third Amendment to the Plan. *See* Securities Exchange Act Release No. 69287, 78 FR 21483 (Apr. 10, 2013). On September 3, 2013, the Commission published for immediate effectiveness the Fourth Amendment to the Plan. *See* Securities Exchange Act Release No. 70273 (Aug. 27, 2013), 78 FR 54321 (Fourth Amendment). On September 26, 2013, the Commission approved the Fifth Amendment to the Plan. *See* Securities Exchange Act Release No. 70530, 78 FR 60937 (Oct. 2, 2013). On January 13, 2014, the Commission published for immediate effective the Sixth Amendment to the Plan. *See* Securities Exchange Act Release No. 71247 (Jan. 7, 2014), 79 FR 2204 (Sixth Amendment). On April 3, 2014, the Commission approved the Seventh Amendment to the Plan. *See* Securities Exchange Act Release No. 71851, 79 FR 19687 (Apr. 9, 2014). On February 19, 2015, the Commission approved the Eight Amendment to the Plan. *See* Securities Exchange Act Release No. 74323, 80 FR 10169 (Feb. 25, 2015).

[2] 15 U.S.C. 78k–1.

[3] 17 CFR 242.608.

[4] *See* Letter from Elizabeth King, General Counsel, NYSE, to Brent Fields, Secretary, Commission, dated July 31, 2015 (''Transmittal Letter'').

[5] 17 CFR 242.608.

[6] *See* 17 CFR 242.608(a)(4) and (a)(5).

[7] *See* Transmittal Letter, *supra* note 3.

and disseminating a lower price band and upper price band, as provided for in Section V of the Plan. Section VI of the Plan sets forth the limit up-limit down requirements of the Plan, and in particular, that all trading centers in NMS Stocks, including both those operated by Participants and those operated by members of Participants, shall establish, maintain, and enforce written policies and procedures that are reasonably designed to prevent trades at prices that are below the lower price band or above the upper price band for an NMS Stock, consistent with the Plan.

The Plan was initially approved for a one-year pilot period, which began on April 8, 2013.[8] Accordingly, the pilot period was scheduled to end on April 8, 2014. As initially contemplated, the Plan would have been fully implemented across all NMS Stocks within six months of initial Plan operations, which meant there would have been full implementation of the Plan for six months before the end of the pilot period. However, pursuant to the fourth amendment to the Plan,[9] the Participants modified the implementation schedule of Phase II of the Plan to extend the time period as to when the Plan would fully apply to all NMS Stocks. Accordingly, the Plan was not implemented across all NMS Stocks until December 8, 2013. Pursuant to the sixth amendment to the Plan,[10] which further modified the implementation schedule of Phase II of the Plan, the date for full implementation of the Plan was moved to February 24, 2014.

In addition, pursuant to the seventh amendment to the Plan,[11] the pilot period was extended from April 8, 2014 to February 20, 2015, and submission of the assessment of the Plan operations was accordingly extended to September 30, 2014. Without such extension, the Plan would have been in effect for the full trading day for less than two months before the end of the pilot period. The Participants believed that this short period of full implementation of the Plan would have provided insufficient time for both the Participants and the Commission to assess the impact of the Plan and determine whether the Plan should be modified prior to approval on a permanent basis.

On September 29, 2014, the Participants submitted a Participant Impact Assessment,[12] which provided the Commission with the Participants' initial observations in each area required to be addressed under Appendix B to the Plan. On May 28, 2015, the Participants submitted a Supplemental Joint Assessment, in which the Participants recommended that the Plan be adopted as permanent with certain modifications, and discussed the areas of analysis set forth in Appendix B to the Plan.[13] These areas are intended to capture the key measures necessary to assess the impact of the Plan and to support recommendations relating to the calibration of the Percentage Parameters to help ensure that the stated objectives of the Plan are achieved—particularly: Liquidity when approaching price bands; clearly erroneous trades; the appropriateness of the percentage parameters; the attributes of limit states; the impact of limit states on the options markets; whether process adjustments are needed when entering/exiting a limit state; and the length of trading pauses.

The Participants propose to amend Section VIII(C) of the Plan to extend the pilot period through April 22, 2016, to allow the Participants to conduct, and the Commission to consider, further analysis of data in support of the recommendations made in the Supplemental Joint Assessment, including around the attributes of limit states; the length of trading pauses; the use of an alternative reference price at the open of trading; and the alignment of the percentage parameters with the Clearly Erroneous Execution (CEE) thresholds (with the goal of largely eliminating the Participants' CEE authority). Thus, an extension of the pilot period would allow the Participants to finalize and file with the Commission any proposed amendments to the Plan resulting from such recommendations and further analysis. The Participants believe that extending the pilot period is appropriate in the public interest, for the protection of investors and the maintenance of a fair and orderly market because it provides Participants with additional time to perform further analysis on the appropriateness of current Plan components and parameters, and to finalize and propose recommended modifications to the Plan.

The Participants believe that the proposed amendment is consistent with Section 11A of the Securities Exchange Act of 1934 and Rule 608, of Regulation NMS thereunder,[14] which authorizes the Participants to act jointly in preparing, filing and implementing national market system plans. The Participants further believe that extending the pilot period will be beneficial in that it allows "the public, the Participants, and the Commission to assess the operation of the Plan and whether the Plan should be modified prior to approval on a permanent basis."[15]

The Participants note that the amended version of the Plan also includes the revised Appendix A—Schedule 1, which was updated for trading beginning July 1, 2015. As set forth in Appendix A—Percentage Parameters, the Primary Listing Exchange updates Schedule 1 to Appendix A semi-annually based on the fiscal year, and such updates do not require a Plan amendment.

1. Chicago Board Options Exchange, Incorporated Withdrawal

On March 30, 2015, CBOE provided written notice to Participants of CBOE's intent to withdraw from the Plan. Notice of withdrawal was made pursuant to Section IX of the Plan.

CBOE became a Participant due to the operation of the CBOE Stock Exchange, LLC ("CBSX"), a facility of the CBOE. CBSX engaged in NMS stock transactions. The last day of trading on CBSX was April 30, 2014. Because CBOE no longer operates a facility engaged in NMS stock transactions, CBOE would have no additional NMS stock data to provide nor any reason to avail itself of any further right under the Plan. Accordingly, CBOE proposes to be removed from the Plan.

B. Governing or Constituent Documents

The governing documents of the Processor, as defined in Section I(P) of the Plan, will not be affected by the Plan, but once the Plan is implemented, the Processor's obligations will change, as set forth in detail in the Plan.

C. Implementation of Plan

The initial date of the Plan operations was April 8, 2013.

D. Development and Implementation Phases

The Plan was initially implemented as a one-year pilot program in two Phases, consistent with Section VIII of the Plan: Phase I of Plan

[8] *See* Section VIII of the Plan.

[9] *See* Fourth Amendment, *supra* note 1.

[10] *See* Sixth Amendment, *supra* note 1.

[11] *See* Securities Exchange Act Release No. 71851 (April 3, 2014), 79 FR 19687 (April 9, 2014).

[12] *See* Joint SROs letter to Brent J. Fields, Secretary, SEC, dated September 29, 2014 ("Participant Impact Assessment").

[13] *See* Letter from Christopher B. Stone, Vice President, FINRA, to Brent J. Fields, Secretary, SEC, dated May 28, 2015.

[14] 17 CFR 242.608.

[15] *See* Securities Exchange Act Release No. 67091 (May 31, 2012), 77 FR 33498, 33508 (June 6, 2012).

implementation began on April 8, 2013 and was completed on May 3, 2013. Implementation of Phase II of the Plan began on August 5, 2013 and was completed on February 24, 2014. Pursuant to this proposed amendment, the Participants propose to extend the pilot period so that it is set to end April 22, 2016.

E. Analysis of Impact on Competition

The proposed amendment to the Plan does not impose any burden on competition that is not necessary or appropriate in furtherance of the purposes of the Exchange Act. The Participants do not believe that the proposed Plan introduces terms that are unreasonably discriminatory for the purposes of Section 11A(c)(1)(D) of the Exchange Act.

F. Written Understanding or Agreements Relating to Interpretation of, or Participation in the Plan

The Participants have no written understandings or agreements relating to interpretation of the Plan. Section II(C) of the Plan sets forth how any entity registered as a national securities exchange or national securities association may become a Participant.

G. Approval of Amendment of the Plan

Each of the Plan's Participants has executed a written amended Plan.

H. Terms and Conditions of Access

Section II(C) of the Plan provides that any entity registered as a national securities exchange or national securities association under the Exchange Act may become a Participant by: (1) Becoming a participant in the applicable Market Data Plans, as defined in Section I(F) of the Plan; (2) executing a copy of the Plan, as then in effect; (3) providing each then-current Participant with a copy of such executed Plan; and (4) effecting an amendment to the Plan as specified in Section III(B) of the Plan.

I. Method of Determination and Imposition, and Amount of, Fees and Charges

Not applicable.

J. Method and Frequency of Processor Evaluation

Not applicable.

K. Dispute Resolution

Section III(C) of the Plan provides for each Participant to designate an individual to represent the Participant as a member of an Operating Committee. No later than the initial date of the Plan, the Operating Committee shall designate one member of the Operating Committee to act as the Chair of the Operating Committee. Any recommendation for an amendment to the Plan from the Operating Committee that receives an affirmative vote of at least two-thirds of the Participants, but is less than unanimous, shall be submitted to the Commission as a request for an amendment to the Plan initiated by the Commission under Rule 608.

On July 30, 2015, the Operating Committee, duly constituted and chaired by Ms. Karen Lorentz of the NYSE, on behalf of Committee Chairman Mr. Christopher B. Stone of FINRA, met and voted unanimously to amend the Plan as set forth herein in accordance with Section III(C) of the Plan. The Plan Advisory Committee was notified in connection with the Ninth Amendment and was in favor.

III. Solicitation of Comments

Interested persons are invited to submit written data, views, and arguments concerning the foregoing, including whether the proposed Ninth Amendment 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 4–631 on the subject line.*

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number *4–631.* 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 Plan that are filed with the Commission, and all written communications relating to the Plan 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 Participants' principal offices. 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 4–631 and should be submitted on or before October 9, 2015.

By the Commission.

Brent J. Fields,

Secretary.

[FR Doc. 2015–23415 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75912; File No. SR–ISE–2015–27]

Self-Regulatory Organizations; International Securities Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Schedule of Fees

September 14, 2015.

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 September 1, 2015, the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') filed with the Securities and Exchange 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 the Substance of the Proposed Rule Change

The ISE proposes to amend the Schedule of Fees to increase certain complex order fees and rebates as described in more detail below. The text of the proposed rule change is available on the Exchange's Web site (*http://www.ise.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 self-regulatory organization included

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

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 self-regulatory organization 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

The Exchange currently provides volume-based tiered rebates for Priority Customer [3] complex orders when these orders trade with non-Priority Customer orders in the complex order book, or trade with quotes and orders on the regular order book. These complex order rebates are provided to members based on the member's average daily volume (''ADV'') in Priority Customer complex orders in six volume tiers as follows: 0 to 29,999 contracts (Tier 1), 30,000 to 59,999 contracts (Tier 2), 60,000 to 99,999 contracts (Tier 3), 100,000 to 149,999 contracts (Tier 4), 150,000 to 199,999 contracts (Tier 5), and 200,000 or more contracts (Tier 6). Currently, Priority Customer complex orders receive a rebate of $0.30 per contract in Select Symbols [4] and $0.63 per contract in Non-Select Symbols [5] for Tier 1, $0.35 per contract in Select Symbols and $0.71 per contract in Non-Select Symbols for Tier 2, $0.40 per contract in Select Symbols and $0.78 per contract in Non-Select Symbols for Tier 3, $0.43 per contract in Select Symbols and $0.80 per contract in Non-Select Symbols for Tier 4, $0.45 per contract in Select Symbols and $0.82 per contract in Non-Select Symbols for Tier 5, and $0.46 per contract in Select Symbols and $0.83 per contract in Non-Select Symbols for Tier 6.[6] The Exchange now proposes to increase these rebates by $0.01 per contract for members that achieve Tiers 3, 4, 5, and 6. As proposed, the Priority Customer complex order rebate in Select Symbols will be increased to $0.41 per contract for Tier 3, $0.44 per contract for Tier 4, $0.46 per contract for Tier 5, and $0.47 per contact for Tier 6. For Non-Select Symbols the rebate will be increased to $0.79 per contract for Tier 3, $0.81 per contract for Tier 4, $0.83 per contract for Tier 5, and $0.84 per contract for Tier 6. Other rebate amounts will remain unchanged from their current levels.

In addition, the Exchange charges complex order taker fees and an equivalent maker fee that applies specifically when trading against Priority Customer orders. In Select Symbols these fees are $0.46 per contract for Market Maker [7] orders (or $0.43 per contract for Market Makers with total affiliated Priority Customer Complex ADV of 150,000 or more contracts),[8] and $0.47 per contract for Non-ISE Market Maker,[9] Firm Proprietary [10]/Broker-Dealer,[11] and Professional Customer [12] orders. In Non-Select Symbols these fees are $0.85 per contract for Market Maker orders,[13] and $0.87 per contract for Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, and Professional Customer orders. The Exchange now proposes to increase these fees by $0.01 per contract. As proposed, the taker fee and equivalent maker fee for trading against Priority Customer orders in Select Symbols will be increased to $0.47 per contract for Market Maker orders (or $0.44 per contract for Market Makers with total affiliated Priority Customer Complex ADV of 150,000 or more contracts), and $0.48 per contract for Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, and Professional Customer orders. In Non-Select Symbols the fee will be increased to $0.86 per contract for Market Maker orders, and $0.88 per contract for Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, and Professional Customer orders. Preferenced Market Makers will continue to receive the applicable discount of $0.02 per contract when trading against Priority Customer order preferenced to them in the complex order book.[14]

Finally, the Exchange charges a fee for responses to complex crossing orders that is $0.47 per contract for Market Maker, Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, Professional Customer, and Priority Customer orders in Select Symbols. In Non-Select Symbols this response fee is $0.90 per contract for Market Maker orders, and $0.95 per contract for Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, Professional Customer, and Priority Customer orders. The Exchange now proposes to increase its complex order response fees by $0.01 per contract. As proposed, the response fee in Select Symbols will be increased to $0.48 per contract for all market participants, and the response fee in Non-Select Symbols will be increased to $0.91 per contract for Market Maker orders, and $0.96 per contract for Non-ISE Market Maker, Firm Proprietary/Broker-Dealer, Professional Customer, and Priority Customer orders.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[15] in general, and Section 6(b)(4) of the Act,[16] 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 that it is reasonable and equitable to increase the rebates provided to Priority Customer complex orders, as these proposed rebates are designed to attract additional Priority Customer complex order volume to the Exchange. The Exchange already provides volume-based tiered rebates for Priority Customer complex orders, and believes that increasing the rebates will incentivize members to send additional order flow to the ISE in order to achieve these rebates for their Priority Customer complex order volume, creating additional liquidity to

[3] A ''Priority Customer'' is a person or entity that is to a broker/dealer in securities, and does not place more than 390 orders in listed options per day on a average during a calendar month for its own beneficial account(s), as defined in Rule 100(a)(37A).

[4] ''Select Symbols'' are options overlying all symbols listed on the ISE that are in the Penny Pilot Program.

[5] ''Non-Select Symbols'' are options overlying all symbols excluding Select Symbols.

[6] These rebates are provided per contract per leg if the order trades with non-Priority Customer orders in the complex order book, or trades with quotes and orders on the regular order book.

[7] The term ''Market Makers'' refers to ''Competitive Market Makers'' and ''Primary Market Makers'' collectively. *See* Rule 100(a)(25).

[8] ISE Market Makers or making or taking liquidity receive a discount of $0.02 when trading against Priority Customer orders preferenced to them in the complex order book in equity options that are able to be listed and traded on more than one options exchange. This discount does not apply to FX Options Symbols or to option classes designated by the Exchange to receive a guaranteed allocation pursuant to ISE Rule 722(b)(3)(i)(B).

[9] A ''Non-ISE Market Maker'' is a market maker as defined in Section 3(a)(38) of the Securities Exchange Act of 1934, as amended, registered in the same options class on another options exchange.

[10] A ''Firm Proprietary'' order is an order submitted by a member for its own proprietary account.

[11] A ''Broker-Dealer'' order is an order submitted by a member for a broker-dealer account that is not its own proprietary account.

[12] A ''Professional Customer'' is a person or entity that is not a broker/dealer and is not a Priority Customer.

[13] ISE Market Makers making or taking liquidity receive a discount of $0.02 when trading against Priority Customer orders preferenced to them in the complex order book in equity options that are able to be listed and traded on more than one options exchange. This discount does not apply to FX Options Symbols or to option classes designated by the Exchange to receive a guaranteed allocation pursuant to ISE Rule 722(b)(3)(i)(B).

[14] *See* notes 6 [sic] and 11 [sic] supra.

[15] 15 U.S.C. 78f.

[16] 15 U.S.C. 78f(b)(4).

the benefit of all members that trade complex orders on the Exchange. The Exchange also believes that the corresponding increase to the complex order taker fee and complex order maker fee for trading against Priority Customer orders, as well as the fee for responses to complex crossing orders, is reasonable and equitable as the proposed fees are set at levels that the Exchange believes will continue to be attractive to market participants that trade on ISE, and that are competitive with fees charged by other options exchanges.

The Exchange notes that Priority Customer orders will continue to receive complex order rebates,[17] while other market participants will continue to pay a fee. The Exchange does not believe that this is unfairly discriminatory as a Priority Customer is by definition not a broker or dealer in securities, and does not place more than 390 orders in listed options per day on average during a calendar month for its own beneficial account(s). This limitation does not apply to participants whose behavior is substantially similar to that of market professionals, including Professional Customers, who will generally submit a higher number of orders (many of which do not result in executions) than Priority Customers. The Exchange also notes that Market Maker orders will continue to be eligible for lower fees than other non-Priority Customer orders. The Exchange does not believe that it is unfairly discriminatory provide lower fees to Market Maker orders as Market Makers are subject to additional requirements and obligations (such as quoting requirements) that other market participants are not.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[18] the Exchange does not believe that the proposed rule change will impose any burden on intermarket or intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange believes that the proposed complex order fees and rebates remain competitive with fees and rebates offered on other options exchanges. The Exchange operates in a highly competitive market in which market participants can readily direct their order flow to competing venues. In such an environment, the Exchange must continually review, and consider adjusting, its fees and rebates to remain competitive with other exchanges. For the reasons described above, the Exchange believes that the proposed fee changes reflect this competitive environment.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange has not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act [19] and subparagraph (f)(2) of Rule 19b–4 thereunder,[20] because it establishes a due, fee, or other charge imposed by ISE.

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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or 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–ISE–2015–27 on the subject line.

Paper Comments

- Send paper comments in triplicate to Brent J. Fields, Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–ISE–2015–27. 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 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–ISE–2015–27, and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[21]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23398 Filed 9–17–15; 8:45 am]

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75919]

Order Pursuant to Sections 15F(b)(6) and 36 of the Securities Exchange Act of 1934 Extending Certain Temporary Exemptions and a Temporary and Limited Exception Related to Security-Based Swaps

September 15, 2015.

I. Introduction

On June 15, 2011, the Securities and Exchange Commission (''Commission'') issued an order granting temporary exemptions and exceptions from compliance with certain provisions of

[17] With the exception of responses to complex crossing orders where Priority Customers are charged a fee like other market participants.

[18] 15 U.S.C. 78f(b)(8).

[19] 15 U.S.C. 78s(b)(3)(A)(ii).

[20] 17 CFR 240.19b–4(f)(2).

[21] 17 CFR 200.30–3(a)(12).

the Securities Exchange Act of 1934 (''Exchange Act'') [1] applicable to security-based swaps (''SB swaps''), that were amended or added by the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (''Dodd-Frank Act'').[2] The Temporary Exemptions Order provided, among other things, a temporary exemption from Section 3E(f) of the Exchange Act for security-based swap dealers and major security-based swap participants (together, ''SBS Entities''), a temporary and limited exception from Section 15F(b)(6) of the Exchange Act with respect to persons then currently associated with SBS Entities, and temporary exemptions from Section 29(b) of the Exchange Act with respect to violations of Sections 3E(f) and 15F(b)(6) in connection with SB swap contracts entered into on or after July 16, 2011. The Commission is extending the exemption from Section 3E(f) and exception from Section 15F(b)(6) until the compliance date of rules we have adopted to establish a process by which SBS Entities can register (and withdraw from registration) with the Commission.[3] In addition, the Commission is specifying when the related exemption for Section 29(b) with respect to SB swap contracts that involve violations of Sections 3E(f) or 15F(b)(6) will expire.

II. Background

Title VII of the Dodd-Frank Act amended the Exchange Act to establish a new regulatory framework for the security-based swap markets. The provisions of Title VII generally were effective as of July 16, 2011, unless a rulemaking or other Commission action is required. The Temporary Exemptions Order provided guidance with respect to the compliance dates of Exchange Act provisions added by Title VII. It also identified those provisions with which compliance was required by the effective date of the Title VII amendments to the Exchange Act and those with which compliance is triggered by registration, adoption of final rules, or other action by the Commission.[4] Where compliance was required by the effective date of Title VII, the Temporary Exemptions Order granted certain temporary exemptions and exceptions where necessary or appropriate in the public interest, and consistent with the protection of investors.[5] The Temporary Exemptions Order included temporary exemptions from Sections 3E(f) and 29(b), and a temporary and limited exception from Section 15F(b)(6).[6]

Section 3E of the Exchange Act, added by Section 763(d) of the Dodd-Frank Act, regulates the collection and handling of collateral for SB swaps, and sets out certain rights of the counterparties who deliver such collateral.[7] Section 3E(f) requires SBS Entities to segregate initial margin amounts delivered by their counterparties in uncleared SB swap transactions if requested to do so by such counterparties.[8] The statutory compliance date for Section 3E(f) was July 16, 2011. As explained in the Temporary Exemptions Order, the segregation required under Section 3E(f) will require expenditures of resources and time, such as the establishment of accounts and the adoption of policies and procedures setting forth the proper collection and maintenance of collateral. The Commission found that a temporary exemption from Section 3E(f) for SBS Entities was necessary or appropriate in the public interest, and was consistent with the protection of investors because it would allow persons to register as an SBS Entity in accordance with the applicable registration requirements, once established, prior to expending resources to comply with the provisions of Section 3E(f), and because it would give SBS Entities additional time to establish the necessary accounts and adopt the policies and procedures required by Section 3E(f).[9] Under the Temporary Exemption Order, the temporary exemption from Section 3E(f) would expire on the date upon which the rules adopted by the Commission to register SBS Entities become effective.

Section 15F of the Exchange Act, added by Section 764(a) of the Dodd-Frank Act, establishes the regulatory framework for SBS Entities.[10] Section 15F(b)(6) provides that ''except to the extent otherwise provided by rule, regulation or order of the Commission,'' it shall be unlawful for an SBS Entity to permit an associated person who is subject to a statutory disqualification to effect or be involved in effecting security-based swaps on its behalf, if the SBS Entity knew or should have known of the statutory disqualification.[11] In the Temporary Exemptions Order, the Commission exercised its authority under Section 15F(b)(6) to provide a temporary and limited exception for SBS Entities from the application of the prohibition in that section. Specifically, the Temporary Exemptions Order provides that persons subject to a statutory disqualification who were, as of July 16, 2011, associated with an SBS Entity and who effected or were involved in effecting security-based swaps on behalf of such SBS Entity could continue to be associated with an SBS Entity until the date upon which rules adopted by the Commission to register SBS Entities become effective. In providing this exception, the Commission explained that it intended to separately consider issues related to how an associated person that is subject to a statutory disqualification may be involved in the security-based swap business of the SBS Entity.[12] The Commission also noted that existing business relationships and market activity could be unnecessarily disrupted if market participants were required to comply with Section 15F(b)(6) before the Commission considers, through notice and comment rulemaking, whether to adopt a procedure for potential modifications of the effect of statutory disqualifications under Title VII of the Dodd-Frank Act for SBS Entities and what any such procedure would require.[13]

Section 29(b) of the Exchange Act generally provides that contracts made in violation of any provision of the Exchange Act, or the rules thereunder, shall be void ''(1) as regards the rights of any person who, in violation of any such provision, . . . shall have made or engaged in the performance of any such contract, and (2) as regards the rights of any person who, not being a party to such contracts, shall have acquired any right thereunder with actual knowledge of the facts by reason of which the

[1] 15 U.S.C. 78a *et seq.*

[2] *See* Temporary Exemptions and Other Temporary Relief, Together With Information on Compliance Dates for New Provisions of the Securities Exchange Act of 1934 Applicable to Security-Based Swaps, Exchange Act Release No. 64678 (June 15, 2011), 76 FR 36287 (June 22, 2011) (''Temporary Exemptions Order'').

[3] *See* Registration Process for Security-Based Swap Dealers and Major Security-Based Swap Participants, Exchange Act Release No. 75611 (Aug. 5, 2015), 80 FR 48964 (Aug.14, 2015) (''Registration Adopting Release'').

[4] *See* Temporary Exemptions Order.

[5] *See id.*

[6] Section 36(c) of the Exchange Act, 15 U.S.C. 78mm(c), limits the Commission's exemptive authority with respect to certain provisions of the Exchange Act added by Title VII, including Section 15F. However, Section 15F(b)(6) expressly authorizes the Commission to establish exceptions to this provision by rule, regulation, or order.

[7] 15 U.S.C. 78c–5.

[8] 15 U.S.C. 78c–5(f).

[9] *See* Temporary Exemptions Order n. 98 (providing that, ''Notwithstanding the exemption granted, market participants in uncleared SB swaps may continue to voluntarily negotiate for and receive similar protections to those provided in section 3E(f) of the Exchange Act, 15 U.S.C. 78c–5(f), until compliance with such section 3E(f) is required.'').

[10] 15 U.S.C. 78o–10.

[11] 15 U.S.C. 78o–10(b)(6).

[12] *See* Temporary Exemptions Order at 36301.

[13] *See id.*

making or performance of such contracts in violation of any such provision . . . .'' [14] In the Temporary Exemptions Order, the Commission temporarily exempted any SB swap contract entered into on or after July 16, 2011 from being void or considered voidable by reason of Section 29(b) because any person that is a party to a contract violated a provision of the Exchange Act that was amended or added by Title VII of Dodd-Frank and for which the Commission has taken the view that compliance will be triggered by registration of a person or by adoption of final rules by the Commission, or has provided an exception or exemption in the Temporary Exemptions Order, until such date as the Commission specifies. The temporary exemption from Section 29(b) applies to contracts that would otherwise involve violations of, among other provisions, Sections 3E(f) or 15F(b)(6) of the Exchange Act.

The Commission received several comments in response to the Temporary Exemptions Order.[15] Although none of the commenters specifically referred to Sections 3E(f), 15F(b)(6), or 29(b), one commenter noted that the Temporary Exemptions Order was, in general, reasonable in terms of its scope and duration.[16] In particular, the commenter stated that the exemption from specific requirements under the Dodd-Frank Act was appropriate where the Commission had not completed ''other steps, such as finalizing rules, setting up the registration regime, or establishing infrastructure.'' [17] Another commenter urged the Commission ''to align the implementation of the self-operative provisions with the provisions that are dependent on rulemaking to ensure a coherent realization of the new swaps regulatory regime.'' [18]

III. Discussion

In August, 2015, the Commission adopted rules to establish a process by which SBS Entities can register (and withdraw from registration) with the Commission (''Registration Rules'').[19] These rules will become effective October 13, 2015, but compliance with the Registration Rules will not be required until the later of: Six months after the date of publication in the **Federal Register** of final rules establishing capital, margin and segregation requirements for SBS Entities; [20] the compliance date of final rules establishing recordkeeping and reporting requirements for SBS Entities; [21] the compliance date of final rules establishing business conduct requirements under Sections 15F(h) and 15F(k) of the Exchange Act; [22] or the compliance date for final rules establishing a process for a registered SBS Entity to make an application to the Commission to allow an associated person who is subject to a statutory disqualification to effect or be involved in effecting security-based swaps on the SBS Entity's behalf (''Registration Compliance Date''). At the same time, the Commission also proposed rules that would, if adopted, establish a process for an SBS Entity to make an application to the Commission to allow an associated person subject to statutory disqualification to effect or be involved in effecting security-based swaps on behalf of the SBS Entity.[23]

Under the terms of the Temporary Exemptions Order, the temporary exemption from Section 3E(f) of the Exchange Act and exception from Section 15F(b)(6) of the Exchange Act will expire when rules adopted by the Commission to register SBS Entities become effective. Accordingly, absent an extension, the temporary exemption from the segregation requirements in Section 3E(f) and exception from the prohibition in Section 15F(b)(6) in the Temporary Exemptions Order will expire upon the effective date of the Registration Rules, even though SBS Entities would not be required to register until the Registration Compliance Date. As stated in the Temporary Exemptions Order, the Commission continues to believe that persons should be able to register in accordance with the applicable registration requirements prior to expending resources to comply with Section 3E(f). Therefore, the Commission is extending the temporary exemption from the requirements of Section 3E(f) until the Registration Compliance Date.[24]

The Commission also continues to believe that existing business relationships and market activity may be unnecessarily disrupted if market participants were required to comply with Section 15F(b)(6) of the Exchange Act before the Commission considered, through notice and comment rulemaking, whether to adopt a procedure for potential modifications of the effect of statutory disqualifications under Title VII for SBS Entities, and what any such procedure would require.[25] As noted above, the Commission has proposed rules relating to the requirements of Section 15F(b)(6). The Registration Compliance Date will occur no earlier than final rules establishing a process for a registered

[14] 15 U.S.C. 78cc(b).

[15] *See* Letter from American Bankers Association, Financial Services Roundtable, Futures Industry Association, Institute of International Bankers, International Swaps and Derivatives Association, Investment Company Institute, Securities Industry and Financial Markets Association, and U.S. Chamber of Commerce, (June 10, 2011); Letter from Jirí Król, Alternative Investment Management Association Limited (July 1, 2011); Letter from Bruce C. Bennett, Covington and Burling LLP (July 1, 2011); Letter from Dennis M. Kelleher, Stephen W. Hall, Better Markets, Inc. (July 6, 2011); Letter from Jeff Gooch, MarkitSERV (July 15, 2011); Letter from Kevin Gould, Markit North America, Inc. (July 26, 2011), *available at http://www.sec.gov/comments/s7-24-11/s72411.shtml.*

[16] *See* Letter from Dennis M. Kelleher, Stephen W. Hall, Better Markets, Inc. (July 6, 2011), at 2, *available at http://www.sec.gov/comments/s7-24-11/s72411-3.pdf.*

[17] *See id.*

[18] *See* Letter from American Bankers Association, Financial Services Roundtable, Futures Industry Association, Institute of International Bankers, International Swaps and Derivatives Association, Investment Company Institute, Securities Industry and Financial Markets Association, and U.S. Chamber of Commerce (June 10, 2011).

[19] *See* Registration Adopting Release.

[20] The Commission previously has proposed rules to establish capital, margin and segregation requirements for SBS Entities. *See* Capital, Margin, and Segregation Requirements for Security-Based Swap Dealers and Major Security-Based Swap Participants and Capital Requirements for Broker-Dealers, Exchange Act Release No. 68071 (Oct. 18, 2012), 77 FR 70213 (Nov. 23, 2012).

[21] The Commission previously has proposed rules to establish recordkeeping and reporting requirements for SBS Entities. *See* Recordkeeping and Reporting Requirements for Security-Based Swap Dealers, Major Security-Based Swap Participants, and Broker-Dealers; Capital Rule for Certain Security-Based Swap Dealers, Exchange Act Release No. 71958 (Apr. 17, 2014), 79 FR 25193 (May 2, 2014).

[22] The Commission previously has proposed rules to establish business conduct standards for SBS Entities. *See* Business Conduct Standards for Security-Based Swap Dealers and Major Security-Based Swap Participants, Exchange Act Release No. 64766 (June 29, 2011), 76 FR 42395 (July 18, 2011).

[23] Applications by Security-Based Swap Dealers or Major Security-Based Swap Participants for Consent for Associated Persons to Effect or Be Involved in Effecting Security-Based Swaps, Exchange Act Release No. 75612 (Aug. 5, 2105), 80 FR 51683 (Aug. 25, 2015) (proposing new Rule of Practice 194).

[24] The Commission also notes that this extension will allow persons to have the ability to review the final capital, margin and segregation rules before being required to comply with the requirements of Section 3E(f), as the compliance date of the Registration Rules will occur no earlier than six months after the date of publication in the **Federal Register** of final rules establishing capital, margin and segregation requirements for SBS Entities.

[25] *See supra* note 23. The Commission has provided guidance in the Registration Adopting Release regarding the dates on which SBS Entities will become subject to registration requirements based on their status as either a SBS Dealer or Major SBS Participant. *See* Registration Adopting Release, 80 FR at 48988. In accordance with this guidance, we do not believe that any entity will have the status of an SBS Entity prior to the Registration Compliance Date. However, for the avoidance of doubt and possible legal uncertainty, the Commission is extending the previously granted temporary exemption from Section 3E(f) and the temporary and limited exception from Section 15F(b)(6) until the Registration Compliance Date.

SBS Entity to make an application to the Commission to allow an associated person who is subject to a statutory disqualification to effect or be involved in effecting security-based swaps on the SBS Entity's behalf. Accordingly, the Commission is extending the temporary and limited exception from the requirements of Section 15F(b)(6) until the Registration Compliance Date.

As discussed in the Temporary Exemptions Order, the Commission does not believe that Section 29(b) of the Exchange Act would apply to the provisions of Title VII for which the Commission has taken the view that compliance will either be triggered by registration of a person or by adoption of final rules by the Commission, or for which the Commission has provided an exception or exemption in that order. For the avoidance of doubt and to avoid possible legal uncertainty or market disruption, the Temporary Exemptions Order granted a temporary exemption from Section 29(b) until such date as the Commission specifies.[26] The Commission believes that the exemption from Section 29(b) provided under the Temporary Exemptions Order with respect to Sections 3E(f) and 15F(b)(6) of the Exchange Act will continue to apply during the period of time covered by the extensions in this Order. However, to avoid any doubt or possible legal uncertainty regarding the continuing availability of the temporary exemption from Section 29(b) with respect to Sections 3E(f) and 15(b)(6), the Commission is exercising its authority under Section 36 of the Exchange Act to continue the exemption from Section 29(b) with respect to Sections 3E(f) and 15(b)(6) until the Registration Compliance Date.

IV. Conclusion

It is hereby ordered, pursuant to Section 36 of the Exchange Act, that SBS Entities are exempt from the requirements of Section 3E(f) of the Exchange Act until the Registration Compliance Date.

It is hereby further ordered, pursuant to Section 15F(b)(6) of the Exchange Act, that SBS Entities are temporarily excepted from the prohibition of Section 15F(b)(6) with respect to persons subject to a statutory disqualification who were associated with an SBS Entity as of July 16, 2011, and who effect or are involved in effecting SB swaps on behalf of such SBS Entity until the Registration Compliance Date.

It is hereby further ordered, pursuant to Section 36 of the Exchange Act, that no SB swap contract entered into on or after July 16, 2011 shall be void or considered voidable by reason of Section 29(b) of the Exchange Act because any person that is a party to the contract violated Section 3E(f) of the Exchange Act prior to the Registration Compliance Date.

It is hereby further ordered, pursuant to Section 36 of the Exchange Act, that no SB swap contract entered into on or after July 16, 2011 shall be void or considered voidable by reason of Section 29(b) of the Exchange Act because any person that is a party to the contract violated Section 15F(b)(6) of the Exchange Act prior to the Registration Compliance.

By the Commission.

Brent J. Fields,

Secretary.

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SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75914; File No. SR–CBOE–2015–079]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To List Two Additional Products During Extended Trading Hours

September 14, 2015.

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 September 10, 2015, Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (the ''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 two additional products during extended trading hours (''ETH''). The text of the proposed rule change is provided below.

(additions are *italicized;* deletions are [bracketed])

* * * * *

Chicago Board Options Exchange, Incorporated

Rules

* * * * *

Rule 6.1A. Extended Trading Hours

(a)–(b) No change.

(c) *Eligibility.* The Exchange may designate as eligible for trading during Extended Trading Hours any exclusively listed index option designated for trading under Rules 24.2 and 24.9. The following options are approved for trading on the Exchange during Extended Trading Hours:

(i) Standard & Poor's 500 Stock Index (SPX)

(ii) CBOE Volatility Index® (VIX®)

(iii) Standard & Poor's 500 Stock Index (P.M.-Settled) (SPXPM)

(iv) Mini-SPX Index (XSP)

Any series in these classes that are expected to be open for trading during Regular Trading Hours will be open for trading during Extended Trading Hours on that same trading day (subject to Rules 6.2B and 24.13, Interpretation and Policy .03). FLEX options (pursuant to Chapters XXIVA and XXIVB) will not be eligible for trading during Extended Trading Hours.

(d) No change.

(e) *Market-Makers.*

(i) *Appointments.* A Market-Maker's appointment to a class during Regular Trading Hours does not apply during Extended Trading Hours. Market-Makers may request appointments for Extended Trading Hours in accordance with Rule 8.3 and this subparagraph (i). Notwithstanding Rule 8.3(c), a Market-Maker can create a Virtual Trading Crowd (''VTC'') appointment, which confers the right to quote electronically during Extended Trading Hours in the appropriate number of classes selected from the Extended Trading Hours tier and related appointment costs as follows:

Tier	Classes	Appointment cost
Extended Trading Hours	• Options on the CBOE Volatility Index (VIX)	[.5].*4*
	• Options on the Standard & Poor's 500 (SPX)	[.5].*4*
	• *Options on the Standard & Poor's 500 Stock Index (P.M.-Settled) (SPXPM)*	*.1*
	• *Options on the Mini-SPX Index (XSP)*	*.1*

[26] *See* Temporary Exemptions Order at 36305–06.

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

Each Extended Trading Hours Trading Permit held by a Market-Maker has an appointment credit of 1.0. A Market-Maker may select for each Extended Trading Hours Trading Permit the Market-Maker holds any combination of Extended Trading Hours classes, whose aggregate appointment cost does not exceed 1.0.

(ii)–(iv) No change.

(f)–(k) No change.

* * * * *

The text of the proposed rule change is also available on the Exchange's Web site (*http://www.cboe.com/AboutCBOE/CBOELegalRegulatoryHome.aspx*), 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 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 aspects of such statements.

A. Self-Regulatory Organization's Statement of the Purpose of, and Statutory Basis for, the Proposed Rule Change

1. Purpose

In March 2015, the Exchange launched Extended Trading Hours (''ETH'') for options on the S&P 500 Index (''SPX'') and CBOE Volatility Index® (''VIX''), two of the Exchange's exclusively listed options,[3] as alternatives for hedging and other investment purposes, particularly as a complementary investment tool to VIX futures.[4] Rule 6.1A(c) provides that the Exchange may designate as eligible for trading during ETH any exclusively listed index option designated for trading under Rules 24.2 and 24.9. In response to customer demand for additional options to trade during ETH for similar purposes, the Exchange has designated Mini-SPX Index Options (''XSP'') and p.m.-settled options on the Standard & Poor's 500 Stock Index (''SPXpm'') to be eligible for trading during ETH. The proposed rule change amends Rule 6.1A(c) to add these two products to the list of products the Exchange has approved for trading on the Exchange during ETH. CBOE currently lists XSP and SPXpm options during Regular Trading Hours (''RTH''); the proposed rule change merely extends the hours during which these options will trade on the Exchange. The Exchange notes that the S&P 500 Stock Index underlies both of these options, as it does for SPX options, which currently trade during ETH. During ETH, XSP and SPXpm options would trade in accordance with Rule 6.1A as VIX and SPX options currently do.[5] The proposed rule change makes no changes to the trading rules applicable to ETH.

The Exchange lists SPXpm options and p.m.-settled XSP options pursuant to a pilot program.[6] Pursuant to the pilot program, CBOE submits annual reports to the Commission that contain analyses of volume, open interest and trading patterns, as well as interim reports that contain some of the information that is included in the annual reports. The Exchange will include in those annual and interim reports the applicable information regarding SPXpm and p.m.-settled XSP options that trade during ETH.

The Exchange also proposes to amend Rule 6.1A(e)(i) to change the current appointment cost for each of SPX and VIX from .5 to .4 and add an appointment cost of .1 for each of XSP and SPXpm. The Exchange believes these appointment costs are consistent with an analysis of various factors based on which the Exchange determines appointment costs, including competitive forces and trading volume. Because each ETH Trading Permit has an appointment credit of 1.0, a Market-Maker will continue to need to hold only one ETH Trading Permit if it wants to quote in all four products approved for trading during ETH.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Act and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[7] Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[8] requirements that the rules of an exchange be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitating transactions in securities, 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. Additionally, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5)[9] requirement that the rules of an exchange not be designed to permit unfair discrimination between customers, issuers, brokers, or dealers.

In particular, the Exchange believes the proposed rule change will further improve the Exchange's marketplace for the benefit of investors. The listing of two additional products for trading during ETH will provide more hedging and other investment opportunities within the options trading industry that is consistent with the continued globalization of the securities markets. The proposed rule change also allows the Exchange to more effectively compete with exchanges located outside of the United States. The Exchange proposes to make two more products available during ETH in response to demand by investors to have access to these products outside of RTH. During ETH, XSP and SPXpm options would trade in accordance with Rule 6.1A as VIX and SPX options currently do. The proposed rule change makes no changes to the trading rules applicable to ETH; it merely approves for trading during ETH two products that already trade on the Exchange during RTH. Additionally, the S&P 500 index underlies both of these options, as it does for SPX options, which are currently approved for trading during ETH.

The Exchange believes the appointment costs for the four classes approved for trading during ETH are appropriate given various factors considered by the Exchange, including competitive forces and trading volume.

[3] An ''exclusively listed option'' is an option that trades exclusively on an exchange because the exchange has an exclusive license to list and trade the option or has the proprietary rights in the interest underlying the option. An exclusively listed option is different than a ''singly listed option,'' which is an option that is not an ''exclusively listed option'' but that is listed by one exchange and not by any other national securities exchange.

[4] *See* Securities Exchange Act Release No. 34–73704 (November 28, 2014), 79 FR 72044 (December 4, 2014) (SR–CBOE–2014–062) (order granting accelerated approval of proposed rule change to adopt Extended Trading Hours for SPX and VIX).

[5] Rule 6.1A(a) states that all CBOE Rules apply to trading during ETH except as set forth in Rule 6.1A and for Rules that by their terms are inapplicable during ETH or where the context otherwise requires.

[6] *See* Securities Exchange Act Release No. 34–73338 (October 10, 2014), 79 FR 62502 (October 17, 2014) (SR–CBOE–2014–076) (notice of filing and immediate effectiveness of extension of pilot program to May 3, 2016).

[7] 15 U.S.C. 78f(b).

[8] 15 U.S.C. 78f(b)(5).

[9] *Id.*

The Exchange believes that allowing ETH Market-Makers to trade all four available products during ETH while holding only one ETH Trading Permit may encourage Trading Permit Holders to become ETH Market-Makers, as they can quote in more classes for the same cost. Additionally, current ETH Market-Makers can obtain appointments in these two additional classes without having to obtain an additional ETH Trading Permit. This may increase liquidity and result in more competitive pricing in these products during ETH, which will promote just and equitable principles of trade and ultimately benefit investors. The proposed rule change does not result in unfair discrimination, as the appointment costs for these products during ETH will apply to all ETH Market-Makers.

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 that is not necessary or appropriate in furtherance of the purposes of the Act. If CBOE lists XSP and SPXpm options for trading during ETH, all ETH Trading Permit Holders may trade these options during ETH. Additionally, non-ETH Trading Permit Holders may trade these options during ETH through a broker that is an ETH Trading Permit Holder. The proposed rule change is merely extending the trading hours of two products that currently trade on CBOE. The appointment costs for the four products approved for trading during ETH will apply to all ETH Market-Makers. Additionally, ETH Market-Makers will not need to obtain additional ETH Trading Permits to have appointments in the two additional products.

CBOE does not believe the proposed rule change will detriment market participants on other exchanges, as it relates to options listed solely on CBOE and to trading hours during which no other U.S. options exchange is currently open for trading. Market participants on other exchanges are welcome to become ETH Trading Permit Holders, or engage a broker that is an ETH Trading Permit Holder, and trade at CBOE if they determine that this proposed rule change has made CBOE more attractive or favorable.

CBOE believes that the proposed rule change will relieve any burden on, or otherwise promote, competition. As discussed above, listing two additional products for trading during ETH will provide more hedging and other investment opportunities within the options trading industry. The Exchange also believes the proposed rule change could increase its competitive position outside of the United States by providing investors with an additional investment vehicles with respect to their global trading strategies during times that correspond with RTH outside of the United States. The Exchange proposes to make two more products available during ETH in response to demand by investors to have access to these products outside of RTH. Additionally, the Exchange believes the appointment costs for the four products available for trading during ETH, which allow ETH Market-Makers to have appointments in all four products with only one ETH Trading Permit, may increase liquidity and enhance competition in those products during those hours.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received 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, if consistent with the protection of investors and the public interest, the proposed rule change has become effective pursuant to Section 19(b)(3)(A) of the Act [10] and Rule 19b–4(f)(6) thereunder.[11]

A proposed rule change filed under Rule 19b–4(f)(6) normally does not become operative for 30 days after the date of filing. However, Rule 19b–4(f)(6)(iii) permits the Commission to designate a shorter time if such action is consistent with the protection of investors and the public interest. The Exchange requests that the Commission waive the 30-day operative delay to allow the proposed rule change to become effective immediately. In its proposal, the Exchange stated that its proposal does not raise any new or unique issues, and only makes available for trading during ETH two additional exclusively-listed products that the Exchange currently lists and trades during RTH. In addition, the Exchange stated that the proposed changes to the appointment costs for these products is intended to allow Market-Makers to have appointments in all four ETH products without having to obtain an additional ETH Trading Permit. The Commission believes that waiving the 30-day operative delay is consistent with the protection of investors and the public interest.[12] Among other things, the proposed rule change makes no changes to the trading rules applicable to ETH, and the Exchange states that XSP and SPXpm will trade during ETH in the same manner as VIX and SPX currently do during ETH. The Commission notes that the Exchange will include in its annual and interim reports to the Commission the applicable information regarding SPXpm and p.m.-settled XSP options that trade during ETH. Because the proposed rule change involves two exclusively-listed products that already trade during RTH, does not alter the trading rules applicable to ETH, and does not raise any novel or unique regulatory issues, the Commission designates the proposed rule change as operative upon filing.

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–2015–079 on the subject line.*

[10] 15 U.S.C. 78s(b)(3)(A).

[11] 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.

[12] For purposes only of waiving the 30-day operative delay, the Commission has also considered the proposed rule's impact on efficiency, competition, and capital formation. *See* 15 U.S.C. 78c(f).

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CBOE-2015–079. 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–CBOE–2015–079 and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[13]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23395 Filed 9–17–15; 8:45 am]

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[13] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75908; File No. SR–CBOE–2015–026]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Designation of a Longer Period for Commission Action on Proceedings To Determine Whether To Approve or Disapprove a Proposed Rule Change Relating to Rules 6.74A and 6.74B

September 14, 2015.

On March 6, 2015, Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (the ''Commission''), pursuant to Section 19(b)(1) of the Securities Exchange Act of 1934 (the ''Act''),[1] and Rule 19b–4 thereunder,[2] a proposed rule change to amend its rules regarding the solicitation of Market-Makers as the contra party to an agency order entered into the Exchange's Automated Improvement Mechanism (''AIM'') and Solicitation Auction Mechanism (''SAM'') auctions. The proposed rule change was published for comment in the **Federal Register** on March 23, 2015.[3] On May 4, 2015, the Commission extended the time period within which to approve the proposed rule change, disapprove the proposed rule change, or institute proceedings to determine whether to disapprove the proposed rule change, to June 21, 2015.[4] On June 18, 2015, the Commission instituted proceedings to determine whether to approve or disapprove the proposed rule change.[5] On July 21, 2015, the Commission received a letter from the Exchange responding to the Order Instituting Proceedings.[6] Subsequently, the Commission received one other comment letter on the proposed rule change.[7]

Section 19(b)(2) of the Act [8] provides that, after initiating disapproval proceedings, the Commission shall issue an order approving or disapproving the proposed rule change not later than 180 days after the date of publication of notice of filing of the proposed rule change. The Commission may extend the period for issuing an order approving or disapproving the proposed rule change, however, by not more than 60 days if the Commission determines that a longer period is appropriate and publishes the reasons for such determination. In this case, the proposed rule change was published for notice and comment in the **Federal Register** on March 23, 2015.[9] September 19, 2015, is 180 days from that date, and November 18, 2015, is 240 days from that date.

The Commission finds it appropriate to designate a longer period within which to issue an order approving or disapproving the proposed rule change so that it has sufficient time to consider the proposed rule change and the comment letters submitted in response to the Order Instituting Proceedings.

Accordingly, the Commission, pursuant to Section 19(b)(2) of the Act,[10] designates November 18, 2015 as the date by which the Commission shall either approve or disapprove the proposed rule change (File No. SR–CBOE–2015–026).

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[11]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23401 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

[3] *See* Securities Exchange Act Release No. 74519 (March 17, 2015), 80 FR 15264 (''Notice'').

[4] *See* Securities Exchange Act Release No. 74862 (May 4, 2015), 80 FR 26599 (May 8, 2015).

[5] *See* Securities Exchange Act Release No. 75245 (June 18, 2015), 80 FR 36386 (June 24, 2015) (''Order Instituting Proceedings'').

[6] *See* Letter to Brent J. Fields, Secretary, Commission, from Kyle Edwards, Attorney, CBOE, dated July 21, 2015 (''CBOE Letter'').

[7] *See* Letter to Brent J. Fields, Secretary, Commission, from Gavin Rowe, Senior Director, Dash Financial LLC, dated August 11, 2015 (''Dash Financial Letter'').

[8] 15 U.S.C. 78s(b)(2).

[9] *See supra* note 3.

[10] 15 U.S.C. 78s(b)(2).

[11] 17 CFR 200.30–3(a)(57).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75913; File No. SR–CBOE–2015–076]

Self-Regulatory Organizations; Chicago Board Options Exchange, Incorporated; Notice of Filing and Immediate Effectiveness of a Proposed Rule Change To Amend the Fees Schedule

September 14, 2015.

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 September 1, 2015, Chicago Board Options Exchange, Incorporated (the ''Exchange'' or ''CBOE'') filed with the Securities and Exchange Commission (the ''Commission'') the proposed rule

[1] 15 U.S.C. 78s(b)(1).

[2] 17 CFR 240.19b–4.

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 the Substance of the Proposed Rule Change

The Exchange proposes to amend its Fees Schedule. The text of the proposed rule change is available on the Exchange's Web site (*http://www.cboe.com/AboutCBOE/CBOELegalRegulatoryHome.aspx*), 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 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 aspects 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 make certain amendments to its Fees Schedule, effective September 1, 2015.

Extended Trading Hour Fees

First, the Exchange proposes to amend the Fees Schedule with respect to Extended Trading Hours fees. The Exchange notes that it recently amended its rules to offer trading in two exclusively listed options (SPX, including SPXW, and VIX) during extended trading hours from 2:00 a.m. to 8:15 a.m. Chicago time Monday through Friday (''Extended Trading Hours'' or ''ETH''). In conjunction with the adoption of ETH, the Exchange established fees for the trading of SPX, SPXW and VIX options during ETH, including fees for ETH Trading Permits and Bandwidth Packets, as well as for CMI and FIX login IDs. In order to promote and encourage trading during the ETH session, the Exchange had waived ETH Trading Permit and Bandwidth Packet fees for one (1) of each initial Trading Permits and one (1) of each initial Bandwidth Packet, per affiliated TPH, through the first six (6) calendar months immediately following the implementation of ETH, including the month ETH was launched (*i.e.*, through August 31, 2015). The Exchange also waived fees through August 31, 2015 for a CMI and FIX login ID if the CMI and/or FIX login ID is related to a waived ETH Trading Permit and/or waived Bandwidth packet. In order to continue promoting trading during ETH, the Exchange wishes to extend these waivers through December 31, 2015.

Qualified Contingent Cross Transactions

The Exchange next proposes to amend its Fees Schedule with respect to Qualified Contingent Cross (''QCC'') [3] orders. Currently, the Fees Schedule provides for a transaction fee for all non-customer QCC orders of $0.15 per contract side (customer orders are not assessed a charge) and a $0.10 per contract credit for the initiating order side, regardless of origin code. The Exchange proposes to further provide that the $0.10 per contract credit will not be available for customer-to-customer transactions. Particularly, the Exchange notes that it does not collect QCC transaction fees on customer-to-customer transactions (since customers are not assessed QCC transaction fees) and it would not be economically feasible or viable to provide a credit on an order that is trading with an order that is not generating a fee. The Exchange notes that another Exchange also excludes customer-to-customer QCC orders from receiving a rebate.[4]

Linkage

The Exchange proposes to (i) adopt a $0.05 per contract Linkage fee (in addition to the applicable away fees) for customer orders and (ii) increase the Linkage fee for non-customer orders from $0.65 per contract to $0.70 per contract. The Fees Schedule currently provides that, in addition to the customary CBOE execution charges, for each customer order that is routed, in whole or in part, to one or more exchanges in connection with the Options Order Protection and Locked/Crossed Market Plan referenced in Rule 6.80, CBOE shall pass through the actual transaction fee assessed by the exchange(s) to which the order was routed. The Exchange proposes to assess an additional $0.05 per contract for customer orders routed away in addition to the applicable pass through fees. The purpose of these proposed changes is to help recoup costs incurred by the Exchange associated with routing customer and non-customer orders through linkage. The Exchange notes that other exchanges also assess an additional fee on top of passing through transaction fees for customer orders and that the proposed amount of the fee is in line with the amount assessed at another exchange.[5] The Exchange also notes that the amount of the proposed non-customer linkage fee is still lower than corresponding non-customer Linkage fees assessed by other exchanges.[6]

Volume Incentive Program

Next, the Exchange proposes to amend its Volume Incentive Program (''VIP''). Under VIP, the Exchange credits each Trading Permit Holder (''TPH'') the per contract amount set forth in the VIP table resulting from each public customer (''C'' origin code) order transmitted by that TPH (with certain exceptions) which is executed electronically on the Exchange in all underlying symbols excluding Underlying Symbol List A,[7] DJX, MXEA, MXEF, XSP, XSPAM, and mini-options, provided the TPH meets certain volume thresholds in a month.[8] The Exchange first proposes to change the different fee tier thresholds in the VIP. Currently, qualification for the different fee rates at different tiers in the VIP is based on a TPH's percentage of national customer volume in all products, excluding Underlying Symbol List A, DJX, MXEA, MXEF, XSP, XSPAM and mini-options. The current qualification tiers are set to, in ascending order, 0% through 0.75%, above 0.75% through 2.0%, above 2.0% through 2.75%, and above 2.75%. The Exchange proposes to adjust the threshold percentages for Tiers 2 through 4. Specifically, the Exchange is proposing to amend the

[3] A QCC order is comprised of an order to buy or sell at least 1,000 contracts (or 10,000 mini-option contracts) that is identified as being part of a qualified contingent trade, coupled with a contra side order to buy or sell an equal number of contracts.

[4] *See* NASDAQ OMX PHLX LLC (''PHLX'') Pricing Schedule, Section II, Multiply Listed Options Fees.

[5] *See e.g.*, PHLX Pricing Schedule, Section V, Customer Routing Fees.

[6] *See e.g.*, PHLX Pricing Schedule, Section V, Non-Customer Routing Fee of $0.99 per contract.

[7] The following products are included in ''Underlying Symbol List A'': OEX, XEO, RUT, SPX (including SPXw), SPXpm, SRO, VIX, VXST, VOLATILITY INDEXES and binary options.

[8] Excluded from the VIP credit are options in Underlying Symbol List A, DJX, MXEA, MXEF, XSP, XSPAM, mini-options, QCC trades, public customer to public customer electronic complex order executions, and executions related to contracts that are routed to one or more exchanges in connection with the Options Order Protection and Locked/Crossed Market Plan referenced in Rule 6.80 (*see* CBOE Fees Schedule, Volume Incentive Program).

tiers to be, in ascending order, 0% through 0.75%, above 0.75% through 1.50%, above 1.50% through 3.0%, and above 3.0%. The Exchange also proposes to increase the VIP credit for simple orders in Tier 3 from $0.11 per contract to $0.12 per contract and in Tier 4 from $0.14 per contract to $0.15 per contract. The Exchange proposes to increase the VIP credit for complex orders in Tier 3 from $0.22 per contract to $0.24 per contract and in Tier 4 from $0.23 per contract to $0.25 per contract. The purpose of these changes is to incentivize the sending of both simple and complex orders to the Exchange and to adjust the incentive tiers accordingly as competition requires while maintaining an incremental incentive for TPH's to strive for the highest tier level.

Strategy Orders and Fee Cap

The Exchange also proposes to amend the Fees Schedule with respect to rebates offered on strategy executions and make certain clarifications with regards to the Clearing Trading Permit Holder Fee Cap (''Fee Cap''). By way of background, the Fee Cap provides for a cap up to $75,000 on certain order executions in all products except those in Underlying Symbol List A excluding binary options, on Clearing Trading Permit Holder Proprietary (origin code ''F'' or ''L'') orders. For example, transaction fees for Qualified Contingent Cross (''QCC'') [9] orders count towards the $75,000 fee cap. The Exchange notes that transaction fees resulting from certain strategy orders also apply towards reaching the Fee Cap.[10] For all non-customer orders, the Exchange notes that fees are capped at $1,000 for all merger strategies and short stock interest strategies and $700 for reversals, conversions and jelly roll strategies executed on the same trading day in the same option class, excluding any option class on which the Exchange charges the Index License surcharge fee under Footnote 14 of the Fees Schedule. The Fees Schedule also currently provides that these transaction fees are further capped at $25,000 per month per initiating Trading Permit Holder (excluding Clearing Trading Permit Holders, who instead are subject to the $75,000 Fee Cap). Additionally, the Fees Schedule states that floor brokerage fees assessed on these strategies are eligible for a full rebate. In order to qualify for the fee caps and floor brokerage fees rebate, a rebate request with supporting documentation must be submitted to the Exchange within three (3) business days of the transactions.

The Exchange proposes to make a number of amendments and clarifications with respect to the Fee Cap table and Footnote 13 of the Fees Schedule. First, the Exchange proposes to provide that the strategy rebates described in Footnote 13 of the Fees Schedule apply only to equities, Exchange-Traded Funds (''ETFs'') and Exchange-Traded Notes (''ETNs'') options. As such, the Exchange proposes adding this language directly into Footnote 13, as well as appending Footnote 13 to the ETF and ETN Options Rate Table to clarify its applicability.[11] The Exchange also proposes to eliminate the following language from Footnote 13 in conjunction with this change: ''. . . excluding any option class on which the Exchange charges the Index License surcharge fee under footnote 14 of this Fees Schedule.'' The Exchange notes that while the strategy rebates always applied to ETF and ETN options, strategy rebates for reversals, conversations and jelly roll strategies also applied to any index option for which an Index License surcharge fee (under Footnote 14) was not assessed (*e.g.*, XSP). The Exchange notes that it no longer seeks to incentivize strategy orders on index options (that weren't otherwise already excluded) and as such, proposes to exclude all indexes from the rebate. Additionally, the Exchange seeks to eliminate the following language from Footnote 13: ''Floor brokerage fees assessed on any of these strategies are eligible for a full rebate (see below)'', as floor brokerage fees are only assessed for products for which strategy order rebates do not apply and therefore it is unnecessary to maintain this language in the Fees Schedule.

Next, the Exchange proposes to add clarifying language to the Notes section of the Clearing Trading Permit Holder Fee Cap table. Specifically, the Exchange proposes to clarify that transaction fees assessed as part of the strategies cap described in Footnote 13 are including in the Clearing Trading Permit Holder Cap. The Exchange also seeks to make clear that a Clearing Trading Permit Holder that has reached the Fee Cap in a given month would no longer be eligible for the strategy rebates, as no transaction fees would have been assessed on those additional transactions. The Exchange believes the proposed clarifications maintain clarity in the Fees Schedule and reduces potential confusion.

The Exchange next notes that strategy orders can be executed as part of a QCC transaction. The Exchange also notes that, as previously mentioned, all non-customer QCC transactions are subject to a $0.15 per contract transaction fee and a $0.10 per contract credit for the initiating side of the QCC transaction. As QCC transactions already receive a credit, the Exchange seeks to amend the Fees Schedule to provide that any strategies described in Footnote 13 of the Fees Schedule that is tied to a QCC transaction will not be eligible for the rebates provided for in Footnote 13 of the Fees Schedule. The Exchange notes that another exchange currently excludes these transactions from similar caps.[12]

The Exchange lastly proposes to clarify in Footnote 11 of the Fees Schedule and the Notes section of the CBOE Proprietary Products Sliding Scale (''Sliding Scale'') that contract volume resulting from any strategies defined in Footnote 13 for which the strategy cap is applied will not apply towards reaching the qualifying ADV thresholds for the Sliding Scale. The Exchange notes that these contracts are not counted towards these thresholds because such contracts have already received the benefit of the strategy fee cap.

2. Statutory Basis

The Exchange believes the proposed rule change is consistent with the Act and the rules and regulations thereunder applicable to the Exchange and, in particular, the requirements of Section 6(b) of the Act.[13] Specifically, the Exchange believes the proposed rule change is consistent with the Section 6(b)(5) [14] requirements that the rules of an exchange be designed to prevent fraudulent and manipulative acts and practices, to promote just and equitable principles of trade, to foster cooperation and coordination with persons engaged in regulating, clearing, settling, processing information with respect to, and facilitation transactions in securities, to remove impediments to and perfect the mechanism of a free and open market and a national market

[9] A QCC order is comprised of an order to buy or sell at least 1,000 contracts (or 10,000 mini-option contracts) that is identified as being part of a qualified contingent trade, coupled with a contra side order to buy or sell an equal number of contracts.

[10] For details about strategy executions, *see* Footnote 13 of the Fees Schedule.

[11] Footnote 13 is already appended to the Equities Rate Table. *See* CBOE Fees Schedule, Equity Options Rate Table.

[12] *See* PHLX Pricing Schedule, Section II, Multiply Listed Option Fees, which provides that all dividend, merger, short stock interest, reversal and conversion strategy executions are excluded from the Monthly Firm Fee Cap.

[13] 15 U.S.C. 78f(b).

[14] 15 U.S.C. 78f(b)(5).

system, and, in general, to protect investors and the public interest. Additionally, the Exchange believes the proposed rule change is consistent with Section 6(b)(4) of the Act,[15] which requires that Exchange rules provide for the equitable allocation of reasonable dues, fees, and other charges among its Trading Permit Holders and other persons using its facilities.

The Exchange believes extending the waiver of ETH Trading Permit and Bandwidth Packet fees for one of each type of Trading Permit and Bandwidth Packet, per affiliated TPH through December 31, 2015 is reasonable, equitable and not unfairly discriminatory, because it promotes and encourages trading during the ETH session and applies to all ETH TPHs. The Exchange believes it's also reasonable, equitable and not unfairly discriminatory to waive fees for Login IDs related to waived Trading Permits and/or Bandwidth Packets in order to promote and encourage ongoing participation in ETH and also applies to all ETH TPHs.

The Exchange believes it's reasonable, equitable and not unfairly discriminatory to exclude customer-to-customer transactions from the QCC credit because these transactions, unlike customer-to-non customer or non-customer to non-customer transactions, are not assessed a QCC transaction fee. The Exchange notes that other exchanges also exclude customer-to-customer transactions from available rebates.[16]

The Exchange's proposal to increase the Linkage fee from $0.65 per contract to $0.70 per contract for non-customer orders and to adopt a $0.05 per contract fee (in addition to applicable transaction fees) for customer orders is reasonable because the increase non-customer fee and adoption of the customer fee will help offset the costs associated with routing orders through Linkage. Additionally, the proposed amounts are reasonable as they are in line with amounts charged by other Exchanges for similar transactions.[17] The Exchange believes it's equitable and not unfairly discriminatory to assess higher linkage rates to non-customers as opposed to customers because if a non-customer market participant wishes to avoid the Linkage fee, it may choose to specify that the Exchange not route orders away on its behalf or designate the order as Immediate or Cancel, which would prevent the order from linking away to another Exchange. Moreover, a non-customer market participant may route directly to exchanges posting the best market if desired to avoid Linkage routing fees.

The Exchange believes the proposed change to amend the fee tier thresholds in VIP are reasonable. Specifically, the Exchange believes it's reasonable to decrease the upper threshold in the second tier (and thus the corresponding lower threshold in the third tier) and increase the upper threshold in the third tier (and therefore the corresponding threshold in the fourth tier) because the slight change is designed to provide TPHs a greater ability to reach higher tiers and therefore receive higher credits as well as adjust the incentive tiers accordingly as competition requires while maintaining an incremental incentive for TPH's to strive for the highest tier level. This change is also equitable and not unfairly discriminatory because it will be applied to all TPHs uniformly. The Exchange believes that increasing the VIP simple and complex order credits in the third and fourth tiers is reasonable because it will allow all TPHs transmitting public customer simple and complex orders that reach certain volume thresholds to receive an increased credit for doing so. The amounts of the credits being proposed are also closer to the amounts of credits paid to market participants by another exchange for similar transactions.[18] Additionally, the Exchange notes that increasing the credit (and providing higher credits for complex orders than for simple orders) is reasonable, equitable and not unfairly discriminatory because it is intended to incentivize the sending of more complex orders to the Exchange. This should provide greater liquidity and trading opportunities, including for market participants who send simple orders to the Exchange (as simple orders can trade with the legs of complex orders). The greater liquidity and trading opportunities should benefit not just public customers (whose orders are the only ones that qualify for the VIP) but all market participants.

The Exchange believes it's reasonable, equitable and not unfairly discriminatory to apply the strategy rebates described in Footnote 13 of the Fees Schedule to equities, ETFs and ETNs because the Exchange no longer seeks to incentivize sending of strategy orders in index options classes and the proposed change applies to all TPHs. The Exchange believes that removing language relating to index options in Footnote 13 serves 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 preventing any potential confusion regarding which option classes the strategy rebates apply. Similarly, the Exchange believes that eliminating reference to floor brokerage rebates, which apply only to products for which strategy rebates do not apply, alleviates potential confusion, thereby protecting investors and public interest.

The Exchange believes that adding clarifying language to the Fees Schedule to specify that once a Clearing Trading Permit Holder reaches the Fee Cap they are no longer eligible for additional strategy rebates also prevents potential confusion, which removes impediments to and perfects the mechanism of a free and open market and national market system.

The Exchange believes it is reasonable to exclude strategies tied to a QCC transaction from the strategy rebates described in Footnote 13 because those transactions already receive the benefit of a credit under the QCC incentive program and the Exchange does not believe an additional incentive is required. Additionally, another Exchange already excludes these transactions from similar caps.[19] The Exchange believes it's equitable and not unfairly discriminatory to exclude QCC strategy orders from the strategy rebates because the proposed change applies to all TPHs uniformly for these types of transactions.

Finally, the Exchange believes that explicitly clarifying in the Fees Schedule that that contract volume for which a strategy cap (as defined in Footnote 13 of the Fees Schedule) has been applied is not included for purposes of reaching the qualifying ADV thresholds for the CBOE Proprietary Products Sliding Scale maintains clarity in the Fees Schedule

[15] 15 U.S.C. 78f(b)(4).

[16] *See* PHLX Pricing Schedule, Section II, Multiply Listed Option Fees.

[17] *See* PHLX Pricing Schedule, Section V, Non-Customer and Customer Routing Fees.

[18] *See e.g.,* International Securities Exchange, LLC (''ISE'') Schedule of Fees, Section II (which lists complex order fees and rebates). For each public customer order transmitted by a market participant (with certain exceptions) a rebate of between $0.30 per contract and $0.46 per contract in Select Symbols and between $0.63 per contract and $0.83 per contract is given to that market participant, depending on the qualifying thresholds that market participant meets. For each public customer complex order. [*sic*] *See also*, PHLX Pricing Schedule, Section II.B [*sic*], Multiply Listed Options Fees [*sic*], Customer Rebate Program, which provides for a rebate of between $0.10 per contract and $0.21 per contract for electronically delivered customer simple orders in Penny and Non-Penny Pilot multiply-listed equity and ETF options (excluding SPY) classes.

[19] *See* PHLX Pricing Schedule, Section II, Multiply Listed Option Fees.

and serves 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 preventing any potential confusion regarding whether or not the volume is included towards the Sliding Scale.

B. Self-Regulatory Organization's Statement on Burden on Competition

The Exchange does not believe that the proposed rule changes will impose any burden on competition that are not necessary or appropriate in furtherance of the purposes of the Act. In particular, the Exchange does not believe that the proposed rule change to extend certain ETH fee waivers will impose any burden on intramarket competition because the proposed waiver would apply equally to all CBOE ETH TPHs. Additionally, the Exchange believes the proposed rule change will continue to encourage trading during ETH, which will provide additional liquidity and enhance competition during ETH. The Exchange does not believe that the proposed rule changes will impose any burden on intermarket competition that is not necessary or appropriate in furtherance of the purposes of the Act because the proposed rule change applies only to CBOE.

The Exchange does not believe that the proposed rule change to exclude customer-to-customer transactions from receiving the $0.10 QCC credit imposes a burden on intramarket competition because although customer-to-customer transactions will not be receive a rebate, these transactions are not assessed QCC transaction fees (unlike customer-to-non customer or non-customer to non-customer QCC transactions). The Exchange does not believe that the proposed rule changes will impose any burden on intermarket competition that is not necessary or appropriate in furtherance of the purposes of the Act because the proposed rule change applies only to CBOE and because other Exchanges have similar exclusions.[20]

The Exchange does not believe that the proposed change to the non-customer Linkage fees will impose a burden on intramarket competition because the increase to the non-customer Linkage fee will apply equally to all non-customer orders routed via linkage and will help offset costs associated with routing non-customer orders via linkage. The Exchange does not believe that the proposed change to the customer Linkage fee will impose a burden on intramarket competition because it will apply equally to all customer orders routed via linkage and will help offset costs associated with routing customer orders via linkage. Additionally, the Exchange notes that while the Linkage fee assessed to non-customers is higher than that assessed to customers, non-customer market participants wishing to avoid the Linkage fee may choose to specify that the Exchange not route orders away on its behalf or designate the order as Immediate or Cancel, which would prevent the order from linking away to another Exchange. The Exchange believes the proposed changes will not impose any burden on intermarket competition that is not necessary or appropriate in furtherance of the purposes of the Act because it only applies to trading on the Exchange and orders sent from the Exchange to other exchanges via Linkage. Additionally, the Exchange notes that the proposed changes remain generally in line with routing fees assessed at other options exchanges.[21]

The Exchange believes the proposed changes to amend the tier thresholds in VIP, as well as increase the VIP credits for simple and complex orders in Tiers 3 and 4 do not impose a burden on intramarket competition because it applies uniformly to all TPHs and incentivizes the sending of more simple and complex orders to the Exchange, which provides greater liquidity and trading opportunities.

The Exchange does not believe that the proposed change to exclude index option classes from the strategy rebates described in Footnote 13 of the Fees Schedule will impose any burden on intramarket competition because it applies to all TPHs executing strategy orders. To the extent that the proposed changes make CBOE a more attractive marketplace for market participants at other exchanges, such market participants are welcome to become CBOE market participants.

The Exchange does not believe that the proposal to exclude strategy orders tied to a QCC transaction from the strategy rebates described in Footnote 13 of the Fees Schedule will impose a burden on intramarket competition because the proposed change applies to all TPHs uniformly and because these transactions already receive the benefit of a credit under the QCC incentive program. To the extent that the proposed changes make CBOE a more attractive marketplace for market participants at other exchanges, such market participants are welcome to become CBOE market participants.

The Exchange does not believe that the proposed rule changes will impose any burden on intermarket competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange notes that it operates in a highly competitive market in which market participants can readily favor competing venues. In such an environment, the Exchange must continually review, and consider adjusting, its fees and credits to remain competitive with other exchanges. For the reasons described above, the Exchange believes that the various proposed rule changes promote a competitive environment. To the extent that the proposed changes make CBOE a more attractive marketplace for market participants at other exchanges, such market participants are welcome to become CBOE market participants. Finally, the Exchange notes that the remaining proposed changes are clarifying in nature and are intended to alleviate confusion and are not intended for competitive purposes.

C. Self-Regulatory Organization's Statement on Comments on the Proposed Rule Change Received From Members, Participants, or Others

The Exchange neither solicited nor received comments on the proposed rule change.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A) of the Act[22] and paragraph (f) of Rule 19b–4[23] 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. If the Commission takes such action, the Commission will institute proceedings to determine whether the proposed rule change should be approved or 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.

[20] *See* PHLX Pricing Schedule, Section II, Multiply Listed Option Fees.

[21] *See* PHLX Pricing Schedule, Section V, Customer and Non-Customer [*sic*] Routing Fees.

[22] 15 U.S.C. 78s(b)(3)(A).

[23] 17 CFR 240.19b–4(f).

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–2015–076 on the subject line.

Paper Comments

• Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File Number SR–CBOE–2015–076. 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 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–CBOE–2015–076, and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[24]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23394 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

[24] 17 CFR 200.30–3(a)(12).

SECURITIES AND EXCHANGE COMMISSION

[Release No. 34–75911; File No. SR–ISE–2015–29]

Self-Regulatory Organizations; International Securities Exchange, LLC; Notice of Filing and Immediate Effectiveness of Proposed Rule Change To Amend the Schedule of Fees

September 14, 2015.

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 September 9, 2015, the International Securities Exchange, LLC (the ''Exchange'' or the ''ISE'') filed with the Securities and Exchange Commission (the ''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 ISE proposes to amend the Schedule of Fees to eliminate the disaster recovery network fee charged to telecommunications vendors that connect to the Exchange's backup datacenter in New York. The text of the proposed rule change is available on the Exchange's Web site (*http://www.ise.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 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 these statements may be examined at the places specified in Item IV below. The self-regulatory organization has prepared summaries, set forth in sections A, B and C below, of the most significant aspects 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 rents cabinet space in its backup datacenter to unaffiliated telecommunications vendors that are responsible for redistributing connectivity to market participants that desire access in order to maintain connectivity to the ISE when the primary datacenter is not operational.[3] The disaster recovery network fee assessed to these telecommunications vendors is based on the amount of cabinet space used by each vendor, and is $2,300 per month for a half-cabinet and $2,800 per month for a full cabinet. The fee is designed to recover the cost of running the backup datacenter, including space, power, and cooling, and also reflects the value that these telecommunications vendors receive from contracting with market participants that use their services to connect to the backup datacenter.[4] As the Exchange is in the process of moving its backup datacenter to a new facility that members will be able to connect to directly, the Exchange now proposes to eliminate the fees charged to telecommunications vendors that are connected to the current site. The telecommunications vendors that are connected to the backup datacenter provide access to members that need connectivity, and are expected to keep providing this access while members are gradually transferred over to the new disaster recovery site. With the upcoming changes, however, the telecommunication vendors, who have already paid substantial hardware and other costs in addition to the fees charged by the Exchange, may not be able to recoup fees from sufficient market participants to cover the cost of maintaining their connections during this period. The Exchange therefore believes that it is appropriate to eliminate the disaster recovery network fee at this time, and believes that doing so will allow telecommunications vendors to continue to provide access to the backup datacenter.

[3] For operational reasons, market participants are not permitted to connect directly to the backup datacenter, and must go through a telecommunication vendor.

[4] Telecommunications vendors contract with interested market participants that access the datacenter through their services for a fee. With this arrangement, the fees that ISE charges telecommunications vendors can be spread across multiple market participants.

2. Statutory Basis

The Exchange believes that the proposed rule change is consistent with the provisions of Section 6 of the Act,[5] in general, and Section 6(b)(4) of the Act,[6] 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 that it is reasonable, equitable, and not unfairly discriminatory to eliminate the disaster recovery network fee as the Exchange is in the process of moving its backup datacenter to a new facility. During the period of this move, the Exchange expects that the telecommunications vendors currently connected to the backup datacenter will continue to provide access to interested parties in order to facilitate access to the Exchange in the event the primary datacenter is not operational. As members move their connections over to the new backup facility, however, the telecommunications vendors will be able to provide service to an increasingly narrow field of market participants. Given the expected reduction in the demand for connectivity through the telecommunication vendors, and the substantial hardware and other costs the vendors have already incurred in establishing and maintaining connectivity to the backup datacenter, the Exchange has determined to eliminate the disaster recovery network fee. The Exchange believes that eliminating this fee during the crossover period will facilitate access to the backup datacenter while the Exchange moves over to its new facility by making it economical for the telecommunications vendors to remain connected and to continue to provide connectivity to interested market participants.

B. Self-Regulatory Organization's Statement on Burden on Competition

In accordance with Section 6(b)(8) of the Act,[7] the Exchange does not believe that the proposed rule change will impose any burden on intermarket or intramarket competition that is not necessary or appropriate in furtherance of the purposes of the Act. The Exchange is eliminating a fee charged to telecommunications vendors connected to the backup datacenter in anticipation of its move to a new facility. This change will facilitate access to the backup datacenter by making it economical for the telecommunications vendors to maintain their connections so that market participants can connect through them until they are moved over to the new backup datacenter, and will not impose 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 not solicited, and does not intend to solicit, comments on this proposed rule change. The Exchange has not received any unsolicited written comments from members or other interested parties.

III. Date of Effectiveness of the Proposed Rule Change and Timing for Commission Action

The foregoing rule change has become effective pursuant to Section 19(b)(3)(A)(ii) of the Act[8] and subparagraph (f)(2) of Rule 19b–4 thereunder,[9] because it establishes a due, fee, or other charge imposed by ISE.

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. If the Commission takes such action, the Commission shall institute proceedings to determine whether the proposed rule should be approved or 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 No. SR–ISE–2015–29 on the subject line.

Paper Comments

- Send paper comments in triplicate to Secretary, Securities and Exchange Commission, 100 F Street NE., Washington, DC 20549–1090.

All submissions should refer to File No. SR–ISE–2015–29. 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 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 No. SR–ISE–2015–29 and should be submitted on or before October 9, 2015.

For the Commission, by the Division of Trading and Markets, pursuant to delegated authority.[10]

Brent J. Fields,

Secretary.

[FR Doc. 2015–23397 Filed 9–17–15; 8:45 am]

BILLING CODE 8011–01–P

[5] 15 U.S.C. 78f.

[6] 15 U.S.C. 78f(b)(4).

[7] 15 U.S.C. 78f(b)(8).

[8] 15 U.S.C. 78s(b)(3)(A)(ii).

[9] 17 CFR 240.19b–4(f)(2).

[10] 17 CFR 200.30–3(a)(12).

U.S. SMALL BUSINESS ADMINISTRATION

[Disaster Declaration #14460 and #14461]

South Carolina Disaster #SC–00028

AGENCY: U.S. Small Business Administration.

ACTION: Notice.

SUMMARY: This is a notice of an Administrative declaration of a disaster for the State of SOUTH CAROLINA dated 09/10/2015.

Incident: Severe Storms and Flooding.

Incident Period: 08/30/2015 through 08/31/2015.

EFFECTIVE DATE: 09/10/2015.

Physical Loan Application Deadline Date: 11/09/2015.

Economic Injury (Eidl) Loan Application Deadline Date: 06/10/2016.

ADDRESSES: Submit completed loan applications to: U.S. Small Business Administration, Processing and Disbursement Center, 14925 Kingsport Road, Fort Worth, TX 76155.

FOR FURTHER INFORMATION CONTACT: A. Escobar, Office of Disaster Assistance, U.S. Small Business Administration, 409 3rd Street SW., Suite 6050, Washington, DC 20416.

SUPPLEMENTARY INFORMATION: Notice is hereby given that as a result of the Administrator's disaster declaration, applications for disaster loans may be filed at the address listed above or other locally announced locations.

The following areas have been determined to be adversely affected by the disaster:

Primary Counties: Charleston.

Contiguous Counties:

South Carolina: Berkeley, Colleton, Dorchester, Georgetown.

The Interest Rates are:

	Percent
For Physical Damage:	
Homeowners with credit available elsewhere	3.750
Homeowners without credit available elsewhere	1.875
Businesses with credit available elsewhere	6.000
Businesses without credit available elsewhere	4.000
Non-profit organizations with credit available elsewhere	2.625
Non-profit organizations without credit available elsewhere	2.625
For Economic Injury:	
Businesses & small agricultural cooperatives without credit available elsewhere	4.000
Non-profit organizations without credit available elsewhere	2.625

The number assigned to this disaster for physical damage is 14460 6 and for economic injury is 14461 0.

The State which received an EIDL Declaration # is South Carolina.

(Catalog of Federal Domestic Assistance Numbers 59002 and 59008)

Dated: September 10, 2015.

Maria Contreras-Sweet,

Administrator.

[FR Doc. 2015–23470 Filed 9–17–15; 8:45 am]

BILLING CODE 8025–01–P

DEPARTMENT OF STATE

[Public Notice: 9279]

Culturally Significant Objects Imported for Exhibition Determinations: "Gauguin to Picasso: Masterworks From Switzerland, The Staechelin & Im Obersteg Collections" and "Daubigny, Monet, Van Gogh: Impressions of Landscape" Exhibitions

ACTION: Notice; correction.

SUMMARY: On July 15, 2015, notice was published on page 41545 of the **Federal Register** (volume 80, number 135) of determinations made by the Department of State pertaining to certain objects to be imported for temporary display in the exhibition "Gauguin to Picasso: Masterworks from Switzerland, The Staechelin & Im Obersteg Collections." The referenced notice is corrected here to provide express notice of an extension in the period of temporary display within the United States of certain of the objects, and express notice of an additional exhibition and venue for a certain object. Notice is hereby given of the following determinations: Pursuant to the authority vested in me by the Act of October 19, 1965 (79 Stat. 985; 22 U.S.C. 2459), Executive Order 12047 of March 27, 1978, the Foreign Affairs Reform and Restructuring Act of 1998 (112 Stat. 2681, *et seq.*; 22 U.S.C. 6501 note, *et seq.*), Delegation of Authority No. 234 of October 1, 1999, Delegation of Authority No. 236–3 of August 28, 2000 (and, as appropriate, Delegation of Authority No. 257 of April 15, 2003), I hereby determine that certain objects to be imported from abroad for temporary exhibition within the United States, are of cultural significance. The objects are imported pursuant to loan agreements with the foreign owners or custodians. I also determine that the exhibition or display of the exhibit objects at The Phillips Collection, Washington, District of Columbia, between on or about October 10, 2015, and on or about January 11, 2017, in the exhibition "Gauguin to Picasso: Masterworks from Switzerland, The Staechelin & Im Obersteg Collections," and at possible additional exhibitions or venues yet to be determined, and the exhibition or display of one of the above-referenced exhibit objects at the Taft Museum of Art, Cincinnati, Ohio, from on or about February 20, 2016, until on or about May 29, 2016, in the exhibition "Daubigny, Monet, Van Gogh: Impressions of Landscape," and at possible additional exhibitions or venues yet to be determined, is in the national interest. I have ordered that Public Notice of these Determinations be published in the **Federal Register**.

FOR FURTHER INFORMATION CONTACT: For further information, including a list of the imported objects, contact the Office of Public Diplomacy and Public Affairs in the Office of the Legal Adviser, U.S. Department of State (telephone: 202–632–6471; email: *section2459@state.gov*). The mailing address is U.S. Department of State, L/PD, SA–5, Suite 5H03, Washington, DC 20522–0505.

Dated: September 16, 2015.

Kelly Keiderling,

Principal Deputy Assistant Secretary, Bureau of Educational and Cultural Affairs, Department of State.

[FR Doc. 2015–23634 Filed 9–17–15; 8:45 am]

BILLING CODE 4710–05–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Aviation Rulemaking Advisory Committee—New Task

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of a new task assignment for the Aviation Rulemaking Advisory Committee (ARAC).

SUMMARY: The FAA assigned the Aviation Rulemaking Advisory Committee (ARAC) a new task to provide recommendations on how the agency can utilize external training providers for its new-hire air traffic controller training program. The ongoing modernization of the air traffic control system, NextGen, will continually introduce advanced tools and procedures to enhance the safety and efficiency of the National Airspace System. Controllers will continue to need to know basic air traffic control skills but will also need to understand how to operate in the future operational environment. The FAA seeks to transform the air traffic controller training structure by shifting the Agency's focus from basic air traffic control qualification training to training the certified controller work force on advanced NextGen tools and procedures. This would mirror the changes that were required in the pilot community. The Agency is exploring alternative options to utilize external training provider capabilities that would expose prospective air traffic controllers to the profession. It would also provide a level of training commensurate to the current Air Traffic Basic Qualification Training, before or during the FAA controller hiring process. This notice informs the public of the new ARAC

activity and solicits membership for the new Air Traffic Controller Basic Qualification Training Working Group.

FOR FURTHER INFORMATION CONTACT:

Tony Price, Federal Aviation Administration, Technical Training Policy and Requirements Specialist, FAA Air Traffic Organization, AJI–232, 800 Independence Avenue SW., Washington, DC, 20591, email *Tony.Price@faa.gov,* telephone (202) 267–1443.

SUPPLEMENTARY INFORMATION:

ARAC Acceptance of Task

As a result of the June 18, 2015 ARAC meeting, the FAA assigned and ARAC accepted this task establishing the Air Traffic Controller Basic Qualification Training Working Group. The Air Traffic Controller Basic Qualification Training Working Group will serve as staff to the ARAC and provide advice and recommendations on the assigned task. The ARAC will review and accept the recommendation report and will submit it to the FAA.

Background

The FAA established the ARAC to provide information, advice, and recommendations on aviation related issues that could result in rulemaking to the FAA Administrator, through the Associate Administrator of Aviation Safety.

The ongoing modernization of the air traffic control system, NextGen, will continually introduce automation tools to enhance the safety and efficiency of the National Airspace System. Fully certified controllers are required to maintain proficiency while also completing additional training to understand how to provide service as the operational environment evolves. To achieve this required integration, the FAA seeks to transform the air traffic controller basic qualification training structure. The Agency is looking for opportunities to utilize external training provider capabilities to expose prospective air traffic controllers to the profession and to provide a basic level of training commensurate with the current level for Air Traffic Control Basic Qualification Training, before or during the FAA controller hiring process. The FAA seeks feedback from external stakeholders on how the agency can accomplish its goals.

The Task

The Air Traffic Controller Basic Qualification Training Working Group will provide to the ARAC an analysis on options for external training provider solutions that restructure the FAA air traffic controller candidate pipeline. Additional considerations include whether a certificated external training program modeled after Part 141 or Part 142 of Title 14 of the Code of Federal Regulations is a way to accomplish agency goals. The recommendations may propose additional alternatives that result in a candidate pipeline with knowledge and skills above the current basic qualification requirements. The Working Group should provide an initial report summarizing the analysis. If the FAA concurs with the recommendation, the tasking may be extended to include a cost and benefit analysis and an evaluation of any necessary rulemaking requirements for implementation.

1. For background information on the topic, the Working Group should review:

a. Air traffic technical training and credentialing programs (for example, FAA Order 3000.22, FAA Order 3120.4, FAA Order 7210.3, and FAA Order 8000.90).

b. Guidance on airman testing, airmen certification, designated examiners, and the FAA Flight Standards Service covered in FAA Order 8900.1, to evaluate the concept of air traffic certified training centers.

c. Title 14 of the Code of Federal Regulations (for example, Parts 61, 65, 141, and 142) for regulatory guidance on various aviation licenses, to include air traffic controllers, flight dispatchers, and pilots.

d. Associated training guidance materials to include course descriptions, lesson outlines, and training handbooks.

e. FAA hiring regulations (for example, as covered in the FAA Human Resources Policy Manual, Office of Personnel Management job standard for Series 2152, and Equal Employment Opportunity Commission guidance) as needed to integrate a proposed solution into the FAA hiring process.

2. The Working Group is tasked to identify possible external training provider solutions. At a minimum, students who complete the program must meet the current standard for Air Traffic Control Basic Qualification Training (solutions may contain options to train students to a higher level of competency).

3. The Working Group may consider rulemaking and/or advisory materials as the solution.

4. Provide initial qualitative and quantitative costs and benefits for each recommendation.

5. Develop an interim report containing recommendations on the findings and results of the tasks explained above.

a. The recommendation report should document both majority and dissenting positions on the findings and the rationale for each position.

b. Any disagreements should be documented, including the rationale for each position and the reasons for the disagreement.

6. The Working Group may be reinstated to assist the ARAC by responding to the FAA's questions or concerns after the interim recommendation report has been submitted.

Schedule

The output of the tasking will be to complete a FAA training process review in order to identify possible external training provider solutions and make a recommendation to the FAA. The interim report is requested to be presented to the ARAC at its June 2016 meeting and submitted to the FAA for review and acceptance no later than July 15, 2016. Should the FAA accept the recommendation of the ARAC, the Working Group may be tasked to evaluate costs and benefits and rulemaking requirements for implementation.

Working Group Activity

The Air Traffic Controller Basic Qualification Training Working Group must comply with the procedures adopted by the ARAC and are as follows:

1. Conduct a review and analysis of the assigned tasks and any other related materials or documents.

2. Draft and submit a work plan for completion of the task, including the rationale supporting such a plan, for consideration by the ARAC.

3. Provide a status report at each ARAC meeting.

4. Draft and submit the interim recommendation report based on the review and analysis of the assigned tasks.

5. Present the initial recommendation report at the ARAC meeting.

6. If the Working Group is reinstated to answer questions the FAA had regarding the recommendation report, present the findings in response to the FAA's questions or concerns about the recommendation report at the ARAC meeting.

Participation in the Working Group

The Air Traffic Controller Basic Qualification Training Working Group will be comprised of technical experts having an interest in the assigned task. A Working Group member need not be a member representative of the ARAC. The FAA would like a wide range of members to ensure all aspects of the tasks are considered in development of the recommendations. The provisions of the August 13, 2014, Office of Management and Budget guidance, ''Revised Guidance on Appointment of Lobbyists to Federal Advisory Committees, Boards, and Commissions'' (79 FR 47482), continues the ban on registered lobbyists participating on Agency Boards and Commissions if participating in their ''individual capacity.'' The revised guidance now allows registered lobbyists to participate on Agency Boards and Commissions in a ''representative capacity'' for the ''express purpose of providing a committee with the views of a nongovernmental entity, a recognizable group of persons or nongovernmental entities (an industry, sector, labor unions, or environmental groups, etc.) or state or local government.'' (For further information see Lobbying Disclosure Act of 1995 (LDA) as amended, 2 U.S.C 1603, 1604, and 1605.)

If you wish to become a member of the Air Traffic Controller Basic Qualification Training Working Group, write the person listed under the caption **FOR FURTHER INFORMATION CONTACT** expressing that desire. Describe your interest in the task and state the expertise you would bring to the Working Group. The FAA must receive all requests by October 19, 2015. The ARAC and the FAA will review the requests and advise you whether or not your request is approved.

If you are chosen for membership on the Working Group, you must actively participate in the Working Group, attend all meetings, and provide written comments when requested. You must devote the resources necessary to support the Working Group in meeting any assigned deadlines. You must keep your management and those you may represent advised of working group activities and decisions to ensure the proposed technical solutions do not conflict with the position of those you represent. Once the Working Group has begun deliberations, members will not be added or substituted without the approval of the ARAC Chair, the FAA, including the Designated Federal Officer, and the Working Group Chair.

The Secretary of Transportation determined the formation and use of the ARAC is necessary and in the public interest in connection with the performance of duties imposed on the FAA by law.

The ARAC meetings are open to the public. However, meetings of the Air Traffic Controller Basic Qualification Training Working Group are not open to the public, except to the extent individuals with an interest and expertise are selected to participate. The FAA will make no public announcement of Working Group meetings.

Issued in Washington, DC, on September 14, 2015.

Lirio Liu,

Designated Federal Officer, Aviation Rulemaking Advisory Committee.

[FR Doc. 2015–23433 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Federal Aviation Administration

Commercial Space Transportation Advisory Committee; Open Meeting

AGENCY: Federal Aviation Administration (FAA), DOT.

ACTION: Notice of Commercial Space Transportation Advisory Committee Open Meeting.

SUMMARY: Pursuant to Section 10(a)(2) of the Federal Advisory Committee Act (Pub. L. 92–463, 5 U.S.C. App. 2), notice is hereby given of a meeting of the Commercial Space Transportation Advisory Committee (COMSTAC). The meeting will take place on Tuesday, October 20, 2015, from 8:00 a.m. to 5:00 p.m., and Wednesday, October 21, 2015, from 8:30 a.m. to 4:30 p.m. at the National Transportation Safety Board Conference Center, 429 L'Enfant Plaza SW., Washington, DC 20594. This will be the 61st meeting of the COMSTAC.

The proposed schedule for the COMSTAC working group meetings on October 20 is below:

—International Space Policy (8:00 a.m.–10:00 a.m.)
—Business/Legal (10:00 a.m.–2:00 p.m.)
—Standards (1:00 p.m.–3:00 p.m.)
—Operations (3:00 p.m.–5:00 p.m.)

The full Committee will meet on October 21, from 8:30 a.m. to 4:30 p.m. The proposed agenda for that meeting features speakers relevant to the commercial space transportation industry; and reports and recommendations from the working groups.

Interested members of the public may submit relevant written statements for the COMSTAC members to consider under the advisory process. Statements may concern the issues and agenda items mentioned above and/or additional issues that may be relevant for the U.S. commercial space transportation industry. Interested parties wishing to submit written statements should contact Larry Scott, COMSTAC Designated Federal Officer, (the Contact Person listed below) in writing (mail or email) by October 9, 2015, so that the information can be made available to COMSTAC members for their review and consideration before the October 20–21 meeting. Written statements should be supplied in the following formats: One hard copy with original signature and/or one electronic copy via email.

A portion of the October 21 meeting will be unavailable to the public (starting at approximately 4:00 p.m.).

An agenda will be posted on the FAA Web site at *www.faa.gov/go/ast.* For specific information concerning the times and locations of the COMSTAC working group meetings, contact the Contact Person listed below.

Individuals who plan to attend and need special assistance, such as sign language interpretation or other reasonable accommodations, should inform the Contact Persons listed below in advance of the meeting.

FOR FURTHER INFORMATION CONTACT: Larry Scott, telephone (202) 267–7982; email *larry.scott@faa.gov*, FAA Office of Commercial Space Transportation (AST–3), 800 Independence Avenue SW., Room 331, Washington, DC 20591.

Complete information regarding COMSTAC is available on the FAA Web site at: *http://www.faa.gov/about/office_org/headquarters_offices/ast/advisory_committee/.*

Issued in Washington, DC, September 11, 2015.

George C. Nield,

Associate Administrator for Commercial Space Transportation.

[FR Doc. 2015–23512 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–13–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0108]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel MYSTIQUE; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by

MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0108. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel MYSTIQUE is:

Intended Commercial Use of Vessel: ''Occasional yacht charters ''

Geographic Region: ''Connecticut, District of Columbia, Florida, Maryland, Massachusetts, New York, Rhode Island, and Virginia ''

The complete application is given in DOT docket MARAD–2015–0108 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23499 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0109]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel EPIPHANY; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0109. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel EPIPHANY is:

Intended Commercial Use Of Vessel: ''Rent out for charter''

Geographic Region: Washington State

The complete application is given in DOT docket MARAD–2015–0109 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23511 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0112]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel CHESTER; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0112. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel CHESTER is:

Intended Commercial Use Of Vessel: ''Bareboat charter''

Geographic Region: Washington State

The complete application is given in DOT docket MARAD–2015–0112 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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 (65 FR 19477).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23514 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015 0106

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel TELL STAR; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0106. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION:

As described by the applicant the intended service of the vessel TELL STAR is:

Intended Commercial Use Of Vessel: ''Tell Star intends to charter guests for day cruises and overnight sight seeing excursions.''

Geographic Region: ''Maine, Massachusetts, Connecticut, New York, New Jersey, Delaware, Maryland, Virginia, North Carolina, South Carolina, Georgia, Florida ''

The complete application is given in DOT docket MARAD–2015–0106 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23497 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–01–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015 0107]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel ANDIAMO; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0107. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION:

As described by the applicant the intended service of the vessel ANDIAMO is:

Intended Commercial Use Of Vessel: ''Occasional yacht charters ''.

Geographic Region: ''Connecticut, District of Columbia, Florida, Maryland, Massachusetts, New York, Rhode Island, and Virginia ''.

The complete application is given in DOT docket MARAD–2015–0107 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23494 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0110]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel OTHILA; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0110. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel OTHILA is:

Intended Commercial Use Of Vessel: ''Pleasure sailing charters primarily leaving port and returning to the same location.''

Geographic Region: ''California''.

The complete application is given in DOT docket MARAD–2015–0110 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23509 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0105]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel SLEIPNIR; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0105. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel SLEIPNIR is:

Intended Commercial Use Of Vessel: ''Sailing lessons and bare boat chartering through WindWorks Sailing Center in Seattle WA.''

Geographic Region: Washington State

The complete application is given in DOT docket MARAD–2015–0105 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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 (65 FR 19477).

By Order of the Maritime Administrator.

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23513 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF TRANSPORTATION

Maritime Administration

[Docket No. MARAD–2015–0111]

Requested Administrative Waiver of the Coastwise Trade Laws: Vessel BLUE DUET; Invitation for Public Comments

AGENCY: Maritime Administration, Department of Transportation.

ACTION: Notice.

SUMMARY: As authorized by 46 U.S.C. 12121, the Secretary of Transportation, as represented by the Maritime Administration (MARAD), is authorized to grant waivers of the U.S.-build requirement of the coastwise laws under certain circumstances. A request for such a waiver has been received by MARAD. The vessel, and a brief description of the proposed service, is listed below.

DATES: Submit comments on or before October 19, 2015.

ADDRESSES: Comments should refer to docket number MARAD–2015–0111. Written comments may be submitted by hand or by mail to the Docket Clerk, U.S. Department of Transportation, Docket Operations, M–30, West Building Ground Floor, Room W12–140, 1200 New Jersey Avenue SE., Washington, DC 20590. You may also send comments electronically via the Internet at *http://www.regulations.gov.* All comments will become part of this docket and will be available for inspection and copying at the above address between 10 a.m. and 5 p.m., E.T., Monday through Friday, except federal holidays. An electronic version of this document and all documents entered into this docket is available on the World Wide Web at *http://www.regulations.gov.*

FOR FURTHER INFORMATION CONTACT: Linda Williams, U.S. Department of Transportation, Maritime Administration, 1200 New Jersey Avenue SE., Room W23–453, Washington, DC 20590. Telephone 202–366–0903, Email *Linda.Williams@dot.gov.*

SUPPLEMENTARY INFORMATION: As described by the applicant the intended service of the vessel BLUE DUET is:

Intended Commercial Use Of Vessel: ''Charter and Sailing lessons''

Geographic Region: Washington State

The complete application is given in DOT docket MARAD–2015–0111 at *http://www.regulations.gov.* Interested parties may comment on the effect this action may have on U.S. vessel builders or businesses in the U.S. that use U.S.-flag vessels. If MARAD determines, in accordance with 46 U.S.C. 12121 and MARAD's regulations at 46 CFR part 388, that the issuance of the waiver will have an unduly adverse effect on a U.S.-vessel builder or a business that uses U.S.-flag vessels in that business, a waiver will not be granted. Comments should refer to the docket number of this notice and the vessel name in order for MARAD to properly consider the comments. Comments should also state the commenter's interest in the waiver application, and address the waiver criteria given in § 388.4 of MARAD's regulations at 46 CFR part 388.

Privacy Act

Anyone is able to search the electronic form of all 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).

By Order of the Maritime Administrator

Dated: September 14, 2015.

T. Mitchell Hudson, Jr.,

Secretary, Maritime Administration.

[FR Doc. 2015–23501 Filed 9–17–15; 8:45 am]

BILLING CODE 4910–81–P

DEPARTMENT OF THE TREASURY

Office of the Comptroller of the Currency

FEDERAL RESERVE SYSTEM

FEDERAL DEPOSIT INSURANCE CORPORATION

Proposed Agency Information Collection Activities; Comment Request

AGENCY: Office of the Comptroller of the Currency (OCC), Treasury; Board of Governors of the Federal Reserve System (Board); Federal Deposit Insurance Corporation (FDIC).

ACTION: Joint notice and request for comment.

SUMMARY: In accordance with the requirements of the Paperwork Reduction Act (PRA) of 1995 (44 U.S.C. chapter 35), the OCC, the Board, and the FDIC (the ''agencies'') may not conduct or sponsor, and the respondent is not required to respond to, an information collection unless it displays a currently valid Office of Management and Budget (OMB) control number. The Federal Financial Institutions Examination Council (FFIEC), of which the agencies are members, has approved the agencies' publication for public comment of a proposal to extend, with revision, the Consolidated Reports of Condition and Income (Call Report), which are currently approved collections of information. The deletions of certain existing data items, the revisions of certain reporting thresholds and certain existing data items, the addition of certain new data items, and certain instructional revisions generally are proposed to take effect as of the December 31, 2015, or the March 31, 2016, report date, depending on the nature of the proposed reporting change. At the end of the comment period, the comments and recommendations received will be analyzed to determine the extent to which the FFIEC and the agencies should modify the proposed revisions prior to giving final approval. The agencies will then submit the revisions to OMB for review and approval.

DATES: Comments must be submitted on or before November 17, 2015.

ADDRESSES: Interested parties are invited to submit written comments to any or all of the agencies. All comments, which should refer to the OMB control number(s), will be shared among the agencies.

OCC: Because paper mail in the Washington, DC area and at the OCC is subject to delay, commenters are encouraged to submit comments by email, if possible. Comments may be sent to: Legislative and Regulatory Activities Division, Office of the Comptroller of the Currency, Attention ''1557–0081, FFIEC 031 and 041,'' 400 7th Street SW., Suite 3E–218, Mail Stop 9W–11, Washington, DC 20219. In addition, comments may be sent by fax to (571) 465–4326 or by electronic mail to *prainfo@occ.treas.gov.*

You may personally inspect and photocopy comments at the OCC, 400 7th Street SW., Washington, DC 20219. For security reasons, the OCC requires that visitors make an appointment to inspect comments. You may do so by calling (202) 649–6700. Upon arrival, visitors will be required to present valid government-issued photo identification and submit to security screening in order to inspect and photocopy comments.

All comments received, including attachments and other supporting materials, are part of the public record and subject to public disclosure. Do not include any information in your comment or supporting materials that you consider confidential or inappropriate for public disclosure.

Board: You may submit comments, which should refer to ''FFIEC 031 and FFIEC 041,'' by any of the following methods:

- *Agency Web site: http://www.federalreserve.gov.* Follow the instructions for submitting comments at: *http://www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm.*
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email: regs.comments@federalreserve.gov.* Include the reporting form numbers in the subject line of the message.
- *Fax:* (202) 452–3819 or (202) 452–3102.
- *Mail:* Robert DeV. Frierson, Secretary, Board of Governors of the Federal Reserve System, 20th Street and Constitution Avenue NW., Washington, DC 20551.

All public comments are available from the Board's Web site at *www.federalreserve.gov/generalinfo/foia/ProposedRegs.cfm* as submitted, unless modified for technical reasons. Accordingly, your comments will not be edited to remove any identifying or contact information. Public comments may also be viewed electronically or in paper in Room MP–500 of the Board's Martin Building (20th and C Streets, NW.) between 9:00 a.m. and 5:00 p.m. on weekdays.

FDIC: You may submit comments, which should refer to ''FFIEC 031 and FFIEC 041,'' by any of the following methods:

- *Agency Web site: http://www.fdic.gov/regulations/laws/federal/*. Follow the instructions for submitting comments on the FDIC's Web site.
- *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the instructions for submitting comments.
- *Email: comments@FDIC.gov.* Include ''FFIEC 031 and FFIEC 041'' in the subject line of the message.
- *Mail:* Gary A. Kuiper, Counsel, Attn: Comments, Room MB–3074, Federal Deposit Insurance Corporation, 550 17th Street NW., Washington, DC 20429.
- *Hand Delivery:* Comments may be hand delivered to the guard station at the rear of the 550 17th Street Building (located on F Street) on business days between 7:00 a.m. and 5:00 p.m.

Public Inspection: All comments received will be posted without change to *http://www.fdic.gov/regulations/laws/federal/* including any personal information provided. Paper copies of public comments may be requested from the FDIC Public Information Center by telephone at (877) 275–3342 or (703) 562–2200.

Additionally, commenters may send a copy of their comments to the OMB desk officer for the agencies by mail to the Office of Information and Regulatory Affairs, U.S. Office of Management and Budget, New Executive Office Building, Room 10235, 725 17th Street NW., Washington, DC 20503; by fax to (202) 395–6974; or by email to *oira_submission@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: For further information about the proposed revisions to the Call Report discussed in this notice, please contact any of the agency staff whose names appear below. In addition, copies of the Call Report forms can be obtained at the FFIEC's Web site (*http://www.ffiec.gov/ffiec_report_forms.htm*).

OCC: Kevin Korzeniewski, Senior Attorney, (202) 649–5490, for persons who are deaf or hard of hearing, TTY, (202) 649–5597, Legislative and Regulatory Activities Division, Office of the Comptroller of the Currency, 400 7th Street SW., Washington, DC 20219.

Board: Mark Tokarski, Acting Federal Reserve Board Clearance Officer, (202) 452–3829, Office of the Chief Data Officer, Board of Governors of the Federal Reserve System, 20th and C Streets NW., Washington, DC 20551. Telecommunications Device for the Deaf (TDD) users may call (202) 263–4869.

FDIC: Gary A. Kuiper, Counsel, (202) 898–3877, and John Popeo, Counsel, (202) 898–6923, Legal Division, Federal Deposit Insurance Corporation, 550 17th Street NW., Washington, DC 20429.

SUPPLEMENTARY INFORMATION: The agencies are proposing to revise and extend for three years the Call Report, which is currently an approved collection of information for each agency.

Report Title: Consolidated Reports of Condition and Income (Call Report).

Form Number: Call Report: FFIEC 031 (for banks and savings associations with domestic and foreign offices) and FFIEC 041 (for banks and savings associations with domestic offices only).

Frequency of Response: Quarterly.

Affected Public: Business or other for-profit.

OCC

OMB Number: 1557–0081.

Estimated Number of Respondents: 1,503 national banks and federal savings associations.

Estimated Time per Response: 59.41 burden hours per quarter to file.

Estimated Total Annual Burden: 357,173 burden hours to file.

Board

OMB Number: 7100–0036.

Estimated Number of Respondents: 850 state member banks.

Estimated Time per Response: 59.90 burden hours per quarter to file.

Estimated Total Annual Burden: 203,660 burden hours to file.

FDIC

OMB Number: 3064–0052.

Estimated Number of Respondents: 4,036 insured state nonmember banks and state savings associations.

Estimated Time per Response: 44.56 burden hours per quarter to file.

Estimated Total Annual Burden: 719,377 burden hours to file.

The estimated time per response for the quarterly filings of the Call Report is an average that varies by agency because of differences in the composition of the institutions under each agency's supervision (*e.g.,* size distribution of institutions, types of activities in which they are engaged, and existence of foreign offices). The average reporting burden for the filing of the Call Report as it is proposed to be revised is estimated to range from 20 to 775 hours per quarter, depending on an individual institution's circumstances.

Type of Review: Revision and extension of currently approved collections.

General Description of Reports

These information collections are mandatory: 12 U.S.C. 161 (for national banks), 12 U.S.C. 324 (for state member banks), 12 U.S.C. 1817 (for insured state nonmember commercial and savings banks), and 12 U.S.C. 1464 (for federal and state savings associations). At present, except for selected data items, these information collections are not given confidential treatment.

Abstract

Institutions submit Call Report data to the agencies each quarter for the agencies' use in monitoring the condition, performance, and risk profile of individual institutions and the industry as a whole. Call Report data serve a regulatory or public policy purpose by assisting the agencies in fulfilling their missions of ensuring the safety and soundness of financial institutions and the financial system and the protection of consumer financial rights, as well as agency-specific missions affecting national and state-chartered institutions, *e.g.,* monetary policy, financial stability, and deposit insurance. Call Reports are the source of the most current statistical data available for identifying areas of focus for on-site and off-site examinations. The agencies use Call Report data in evaluating institutions' corporate applications, including, in particular, interstate merger and acquisition applications for which, as required by law, the agencies must determine whether the resulting institution would control more than ten percent of the total amount of deposits of insured depository institutions in the United States. Call Report data also are used to calculate institutions' deposit insurance and Financing Corporation assessments and national banks' and federal savings associations' semiannual assessment fees.

Current Actions

I. Introduction

The FFIEC launched a formal initiative in December 2014 to identify potential opportunities to reduce burden associated with Call Report requirements for community banks. In embarking on this effort, the FFIEC was responding to industry concerns about the cost and burden associated with the Call Report. The FFIEC's formal initiative comprises actions in five areas, which are discussed below. In addition, as a foundation for the actions it is undertaking, the FFIEC has developed a set of guiding principles for use in evaluating potential additions and deletions of Call Report data items and other revisions to the Call Report. In general, any Call Report changes must meet three guiding principles: (1) The data items serve a long-term regulatory or public policy purpose by assisting the FFIEC's member entities in fulfilling their missions of ensuring the safety and soundness of financial institutions and the financial system and the protection of consumer financial rights, as well as entity-specific missions affecting national and state-chartered institutions; (2) The data items to be collected maximize practical utility and minimize, to the extent practicable and appropriate, burden on financial institutions; and (3) Equivalent data items are not readily available through other means.

As a first action under the FFIEC's Call Report burden-reduction initiative, the agencies are publishing this **Federal Register** notice and requesting comment on a number of proposed burden-reducing changes and certain other proposed Call Report revisions identified during their most recent statutorily mandated review of the information collected in the Call Report.[1] Implementation of the

[1] This review is mandated by section 604 of the Financial Services Regulatory Relief Act of 2006 (12 U.S.C. 1817(a)(11)).

revisions identified during that review had been deferred while the agencies adopted changes to the reporting of regulatory capital information in the Call Report to implement the revised regulatory capital rules issued in July 2013 that took effect as of January 1, 2014, and January 1, 2015.[2]

The FFIEC and the agencies also identified and incorporated into this proposal certain other burden-reducing changes to the Call Report in addition to those identified in the most recent statutorily mandated review of the Call Report. The burden-reducing changes included as part of this first action are not intended to be the only group of Call Report revisions designed to lessen reporting burden for reporting institutions and, in particular, for community banks. Additional burden-reducing changes to the Call Report are expected to result from the other actions being taken by the agencies under the FFIEC's Call Report burden-reduction initiative.

As the second action, the agencies have accelerated the start of the next statutorily mandated review of the existing Call Report data items, which otherwise would have commenced in 2017. Users of Call Report data items at the FFIEC's member entities are participating in a series of surveys being conducted over an 18-month period that began in mid-July 2015. As an integral part of these surveys, users are being asked to fully explain the need for each Call Report data item, how it is used, the frequency with which it is needed, and the population of institutions from which it is needed. Call Report schedules have been placed into groups and prioritized for review, generally based on perceived burden as cited by banking industry representatives. Based on the results of the surveys, the agencies will identify data items that will be considered for elimination, less frequent collection, or new or upwardly revised reporting thresholds. Burden-reducing reporting changes will be proposed for implementation on a flow basis as they are identified during the sequential reviews of groups of Call Report schedules rather than waiting until the completion of the entire review.

As a third action, the agencies are considering the feasibility and merits of creating a less burdensome version of the quarterly Call Report for institutions that meet certain criteria, which may include an asset-size reporting threshold or activity limitations. For example, a report for eligible institutions could exclude the Call Report schedules and items not applicable to institutions below the specified asset-size threshold. The agencies plan to complete their analysis regarding the concept of such a Call Report by year-end 2015. Any plan for a new version of the Call Report would need to be approved by the FFIEC and implemented by the agencies in compliance with the applicable requirements under the PRA.

A fourth action for the agencies is to better understand, through industry dialogue, the aspects of reporting institutions' Call Report preparation process that are significant sources of reporting burden, including where manual intervention by an institution's staff is necessary to report particular information. As an initial step toward gaining this understanding, representatives from the FFIEC's member entities plan to visit a limited number of institutions that have expressed their willingness to host a visit during the third quarter of 2015. Institution staff would be asked to show how they prepare their Call Reports and explain which schedules or data items take a significant amount of time or manual processes to complete and the reasons for this. Findings from on-site visits would help the agencies determine the nature and form of further banker outreach. The information obtained from these activities would assist the agencies in evaluating whether and how it may be possible to reduce reporting burden by revising or redefining Call Report data items.

As the fifth action, the agencies plan to offer periodic training to bankers via teleconferences and webinars that would explain upcoming reporting changes and could also provide guidance on areas of the Call Report bankers find challenging to complete. These events should benefit institutions by reducing Call Report preparation training costs. The first training session was a banker teleconference on February 25, 2015, that included a presentation on the revised Call Report Schedule RC–R regulatory capital reporting requirements that took effect on March 31, 2015, followed by a question-and-answer session. The slide presentation used during the teleconference, an audio recording of this presentation, and a transcript of the entire teleconference have been posted on the FFIEC's Web site.

II. Overview

The agencies are proposing to implement a number of revisions to the Call Report requirements in December 2015 or March 2016, depending on the nature of the proposed revision. The proposed changes, which are discussed in detail in Sections III.A through III.E below and would take effect in December 2015 unless otherwise indicated, include:

- Deletions of certain existing data items pertaining to other-than-temporary impairments from Schedule RI, Income Statement; troubled debt restructurings from Schedule RC–C, Part I, Loans and Leases, and Schedule RC–N, Past Due and Nonaccrual Loans, Leases, and Other Assets; loans covered by FDIC loss-sharing agreements from Schedule RC–M, Memoranda, and Schedule RC–N; and unused commitments to asset-backed commercial paper conduits with an original maturity of one year or less in Schedule RC–R, Part II, Risk-Weighted Assets;
- Increases in existing reporting thresholds for certain data items in five Call Report schedules[3] and the establishment of a reporting threshold for certain data items in Schedule RC–S, Servicing, Securitization, and Asset Sale Activities;
- Instructional revisions addressing the reporting of home equity lines of credit that convert from revolving to non-revolving status in Schedule RC–C, Part I; securities for which a fair value option is elected in Schedule RC, Balance Sheet; and net gains (losses) and other-than-temporary impairments on equity securities that do not have readily determinable fair values in Schedule RI;
- New and revised data items and information of general applicability, including:
  - Increasing the time deposit size threshold used to report certain deposit information from $100,000 to $250,000 in Schedule RC–E, Deposit Liabilities; Schedule RI; and Schedule RC–K, Quarterly Averages;[4]
  - Revising the statements used to describe the level of external auditing work performed for the reporting institution during the preceding year in Schedule RC (effective in March 2016);
  - Adding contact information for the reporting institution's Chief Executive Officer;

[2] See 78 FR 48932 (August 12, 2013); 79 FR 2527 (January 14, 2014); 79 FR 35634 (June 23, 2014); and 80 FR 5618 (February 2, 2015).

[3] The data items for which components in excess of specified reporting thresholds are required to be itemized and described are included in Schedule RI–E, Explanations; Schedule RC–D, Trading Assets and Liabilities; Schedule RC–F, Other Assets; Schedule RC–G, Other Liabilities; and Schedule RC–Q, Assets and Liabilities Measured at Fair Value on a Recurring Basis.

[4] Effective in March 2016 for the data items for the interest expense on and quarterly averages of time deposits in Schedules RI and RC–K, respectively.

◦ Reporting the Legal Entity Identifier for the reporting institution if it already has one (on the Call Report cover page);

◦ Creating additional preprinted captions for itemizing and describing components of certain items that exceed reporting thresholds in Schedules RC–F and RI–E; and

◦ Eliminating the concept of extraordinary items and revising affected data items in Schedule RI (effective in March 2016); and

• New and revised data items of limited applicability, including:

◦ Revising the reporting of certain securities measured under a fair value option in Schedule RC–Q and moving the existing Memorandum items for the fair value and unpaid principal balance of loans (not held for trading) measured under a fair value option from Schedule RC–C, Part I, to Schedule RC–Q;

◦ Revising the information reported in Schedule RI Memorandum items by institutions with total assets of $100 billion or more on the impact on trading revenues of changes in credit and debit valuation adjustments (effective in March 2016);

◦ Adding a new item on ''dually payable'' deposits in foreign branches of U.S. banks to Schedule RC–E, Part II, Deposits in Foreign Offices, on the FFIEC 031 report; and

◦ Revising the information reported about the supplementary leverage ratio by advanced approaches institutions in Schedule RC–R, Part I, Regulatory Capital Components and Ratios (effective in March 2016).

For the Call Report revisions proposed to take effect in December 2015, the agencies invite comment on any difficulties that institutions would encounter in implementing any of these revisions in their year-end 2015 Call Reports.

For the December 31, 2015, and March 31, 2016, report dates, as applicable, institutions may provide reasonable estimates for any new or revised Call Report data item initially required to be reported as of that date for which the requested information is not readily available. The specific wording of the captions for the new or revised Call Report data items discussed in this proposal and the numbering of these data items should be regarded as preliminary.

III. Discussion of Proposed Call Report Revisions

A. Deletions of Existing Data Items

Based on the agencies' review of the information that institutions are required to report in the Call Report, the agencies have determined that the continued collection of the following items is no longer necessary and are proposing to eliminate them effective December 31, 2015:

(1) Schedule RI, Memorandum items 14.a and 14.b, on other-than-temporary impairments [5]

(2) Schedule RC–C, Memorandum items 1.f.(2), 1.f.(5), and 1.f.(6) (and 1.f.(7) on the FFIEC 031), on troubled debt restructurings in certain loan categories that are in compliance with their modified terms;

(3) Schedule RC–N, Memorandum items 1.f.(2), 1.f.(5), and 1.f.(6) (and 1.f.(7) on the FFIEC 031), on troubled debt restructurings in certain loan categories that are 30 days or more past due or on nonaccrual;

(4) Schedule RC–M, items 13.a.(5)(a) through (d) (and (e) on the FFIEC 031), on loans in certain loan categories that are covered by FDIC loss-sharing agreements; and

(5) Schedule RC–N, items 11.e.(1) through (4) (and (5) on the FFIEC 031), on loans in certain loan categories that are covered by FDIC loss-sharing agreements and are 30 days or more past due or on nonaccrual.

In addition, when Schedule RC–R, Part II, is completed properly, item 18.b on unused commitments to asset-backed commercial paper conduits with an original maturity of one year or less is not needed because such commitments should already have been reported in item 10 as off-balance sheet securitization exposures. The instructions for item 18.b explain that these unused commitments should be reported in item 10 and that amounts should not be reported in item 18.b. Accordingly, the agencies are proposing to delete existing item 18.b from Schedule RC–R, Part II. Existing item 18.c of Schedule RC–R, Part II, for unused commitments with an original maturity exceeding one year would then be renumbered as item 18.b.

B. New Reporting Threshold and Increases in Existing Reporting Thresholds

In five Call Report schedules, institutions are currently required to itemize and describe each component of an existing item when the component exceeds both a specified percentage of the item and a specified dollar amount.[6] Based on a preliminary evaluation of the existing reporting thresholds, the agencies have concluded that the dollar portion of the thresholds that currently apply to these items can be increased to provide a reduction in reporting burden without a loss of data that would be necessary for supervisory or other public policy purposes. The percentage portion of the existing thresholds would not be changed. Accordingly, the agencies are proposing to raise from $25,000 to $100,000 the dollar portion of the threshold for itemizing and describing components of:

(1) Schedule RI–E, item 1, ''Other noninterest income;''

(2) Schedule RI–E, item 2, ''Other noninterest expense;''

(3) Schedule RC–F, item 6, ''All other assets;''

(4) Schedule RC–G, item 4, ''All other liabilities;''

(5) Schedule RC–Q, Memorandum item 1, ''All other assets;'' and

(6) Schedule RC–Q, Memorandum item 2, ''All other liabilities.''

The agencies also are proposing to raise from $25,000 to $1,000,000 the dollar portion of the threshold for itemizing and describing components of ''Other trading assets'' and ''Other trading liabilities'' in Schedule RC–D, Memorandum items 9 and 10.

In addition, because institutions with less than $1 billion in total assets typically do not provide support for asset-backed commercial paper conduits, the agencies are proposing to exempt such institutions from completing Schedule RC–S, Memorandum items 3.a.(1), 3.a.(2), 3.b.(1), and 3.b.(2), on credit enhancements and unused liquidity commitments provided to asset-backed commercial paper conduits.

These proposed threshold changes would take effect December 31, 2015.

C. Instructional Revisions

The following proposed instructional revisions would take effect December 31, 2015.

1. Reporting Home Equity Lines of Credit that Convert From Revolving to Non-Revolving Status

Institutions report the amount outstanding under revolving, open-end lines of credit secured by 1–4 family residential properties (commonly known as home equity lines of credit or HELOCs) in item 1.c.(1) of Schedule RC–C, Part I, Loans and Leases. Closed-end loans secured by 1–4 family residential properties are reported in Schedule RC–C, Part I, item 1.c.(2)(a) or (b), depending on whether the loan is a first or a junior lien.[7]

[5] Institutions would continue to complete Schedule RI, Memorandum item 14.c, on net impairment losses recognized in earnings.

[6] See footnote 3.

[7] Information also is separately reported for open-end and closed-end loans secured by 1–4 family residential properties in Schedule RI–B, Part I,

A HELOC is a line of credit secured by a lien on a 1–4 family residential property that generally provides a draw period followed by a repayment period. During the draw period, a borrower has revolving access to unused amounts under a specified line of credit. During the repayment period, the borrower can no longer draw on the line of credit, and the outstanding principal is either due immediately in a balloon payment or is repaid over the remaining loan term through monthly payments. The Call Report instructions do not address the reporting treatment for a home equity line of credit when it reaches its end-of-draw period and converts from revolving to nonrevolving status. Such a loan no longer has the characteristics of a revolving, open-end line of credit and, instead, becomes a closed-end loan. In the absence of instructional guidance that specifically addresses this situation, the agencies have found diversity in how these credits are reported in Schedule RC–C, Part I. Some institutions continue to report home equity lines of credit that have converted to non-revolving closed-end status in item 1.c.(1) of Schedule RC–C, Part I, as if they were still revolving open-end lines of credit, while other institutions recategorize such loans and report them as closed-end loans in item 1.c.(2)(a) or (b), as appropriate.

Therefore, to address this absence of instructional guidance and promote consistency in reporting, the agencies are proposing to clarify the instructions for reporting loans secured by 1–4 family residential properties to specify that after a revolving open-end line of credit has converted to non-revolving closed-end status, the loan should be reported in Schedule RC–C, Part I, item 1.c.(2)(a) or (b), as appropriate. In proposing this clarification, the agencies request comment on whether an instructional requirement to recategorize HELOCs as closed-end loans for Call Report purposes would create difficulties for institutions' loan recordkeeping systems. If so, commenters are encouraged to describe the difficulties this recategorization would create.

2. Reporting Treatment for Securities for Which a Fair Value Option Is Elected

The Call Report Glossary entry for ''Trading Account'' currently states that ''all securities within the scope of the Financial Accounting Standards Board's (FASB) Accounting Standards Codification (ASC) Topic 320, Investments-Debt and Equity Securities (formerly FASB Statement No. 115, ''Accounting for Certain Investments in Debt and Equity Securities''), that a bank has elected to report at fair value under a fair value option with changes in fair value reported in current earnings should be classified as trading securities.'' This reporting treatment was based on language contained in former FASB Statement No. 159, ''The Fair Value Option for Financial Assets and Financial Liabilities,'' but that language was not codified when Statement No. 159 was superseded by current ASC Topic 825, Financial Instruments. Thus, under U.S. GAAP as currently in effect, the classification of all securities within the scope of ASC Topic 320 that are accounted for under a fair value option as trading securities is no longer required. Accordingly, to bring the ''Trading Account'' Glossary entry into conformity with current U.S. GAAP, the agencies are proposing to revise the statement from the Glossary entry quoted above by replacing ''should be classified'' with ''may be classified.''

This revision to the ''Trading Account'' Glossary entry means that an institution that elects the fair value option for securities within the scope of ASC Topic 320 would be able to classify such securities as held-to-maturity or available-for-sale in accordance with this topic based on the institution's intent and ability with respect to the securities. In addition, an institution could choose to classify securities for which a fair value option is elected as trading securities.

Institutions that have been required to classify all securities within the scope of ASC Topic 320 that are accounted for under a fair value option as trading securities also should consider the related proposed changes to Schedule RC–Q, Assets and Liabilities Measured at Fair Value on a Recurring Basis, which are discussed in Section III.E.1 below.

3. Net Gains (Losses) on Sales of, and Other-Than-Temporary Impairments on, Equity Securities That Do Not Have Readily Determinable Fair Values

Institutions report investments in equity securities that do not have readily determinable fair values and are not held for trading (and to which the equity method of accounting does not apply) in Schedule RC–F, item 4, and on the Call Report balance sheet in Schedule RC, item 11, ''Other assets.'' If such equity securities are held for trading, they are reported in Schedule RC, item 5, and in Schedule RC–D, item 9 and Memorandum item 7.b, if applicable. In contrast, investments in equity securities with readily determinable fair values that are not held for trading are reported as available-for-sale securities in Schedule RC, item 2.b, and in Schedule RC–B, item 7, whereas those held for trading are reported in Schedule RC, item 5, and in Schedule RC–D, item 9 and Memorandum item 7.a, if applicable.

In general, investments in equity securities that do not have readily determinable fair values are accounted for in accordance with ASC Subtopic 325–20, Investments—Other—Cost Method Investments (formerly Accounting Principles Board Opinion No. 18, ''The Equity Method of Accounting for Investments in Common Stock''), but are subject to the impairment guidance in ASC Topic 320, Investments—Debt and Equity Securities (formerly FASB Staff Position No. FAS 115–2 and FAS 124–2, ''Recognition and Presentation of Other-Than-Temporary Impairments'').

The Call Report instructions for Schedule RI, Income Statement, address the reporting of realized gains (losses), including other-than-temporary impairments, on held to-maturity and available-for-sale securities as well as the reporting of realized and unrealized gains (losses) on trading securities and other assets held for trading. However, the Schedule RI instructions do not specifically explain where to report realized gains (losses) on sales or other disposals of, and other-than-temporary impairments on, equity securities that do not have readily determinable fair values and are not held for trading (and to which the equity method of accounting does not apply).

The instructions for Schedule RI, item 5.k, ''Net gains (losses) on sales of other assets (excluding securities),'' direct institutions to ''[r]eport the amount of net gains (losses) on sales and other disposals of assets not required to be reported elsewhere in the income statement (Schedule RI).'' The instructions for item 5.k further advise institutions to exclude net gains (losses) on sales and other disposals of securities and trading assets. The intent of this wording was to cover securities designated as held-to-maturity, available-for-sale, and trading securities because there are separate specific items elsewhere in Schedule RI for the reporting of realized gains (losses) on such securities (items 6.a, 6.b, and 5.c, respectively). Thus, the agencies are proposing to revise the instructions for Schedule RI, item 5.k, by clarifying that the exclusions from this item of net gains (losses) on securities and trading

Charge-offs and Recoveries on Loans and Leases; Memorandum items in Schedule RC–C, Part I; Schedule RC–D; Schedule RC–M; and Schedule RC–N.

assets apply to held-to-maturity, available-for-sale, and trading securities and other assets held for trading. At the same time, the agencies are proposing to add language to the instructions for Schedule RI, item 5.k, that explains that net gains (losses) on sales and other disposals of equity securities that do not have readily determinable fair values and are not held for trading (and to which the equity method of accounting does not apply), as well as other-than-temporary impairments on such securities, should be reported in item 5.k. The agencies also are proposing to remove the parenthetic ''(excluding securities)'' from the caption for item 5.k and add in its place a footnote to this item advising institutions to exclude net gains (losses) on sales of trading assets and held-to-maturity and available-for-sale securities.

D. New and Revised Data Items and Information of General Applicability

1. Increase in the Time Deposit Size Threshold

Section 335 of the Dodd-Frank Wall Street Reform and Consumer Protection Act (Pub. L. 111–203) permanently increased the standard maximum deposit insurance amount (SMDIA) from $100,000 to $250,000 effective July 21, 2010. The SMDIA had been increased temporarily from $100,000 to $250,000 by Section 136 of the Emergency Economic Stabilization Act of 2008 (Pub. L. 110–343). In response to the increase in the limit of deposit insurance coverage, the reporting of the amount of ''Total time deposits of $100,000 or more'' in Memorandum item 2.c of Schedule RC–E, Deposit Liabilities, was revised as of the March 31, 2010, report date. As of that date, institutions began to separately report their ''Total time deposits of $100,000 through $250,000'' (Memorandum item 2.c) and their ''Total time deposits of more than $250,000'' (Memorandum item 2.d).

However, the reporting of the quarterly averages, interest expense, and maturity and repricing data for time deposits of $100,000 or more in Schedules RC–K, RI, and RC–E, respectively, have not been updated to reflect the permanent $250,000 deposit insurance limit. In this regard, in its comment letter to the agencies in response to their first request for comments under the Economic Growth and Regulatory Paperwork Reduction Act of 1996,[8] the American Bankers Association recommended revising the Schedule RC–E deposit reporting items to reflect the new FDIC insurance limit of $250,000. Accordingly, the agencies are proposing to revise the time deposit size threshold that applies to the reporting of this information to bring it into alignment with the SMDIA. These proposed changes are illustrated in the following table:

Call report schedule	Current item	Proposed revised item
Schedule RC–K, Quarterly Averages.	Item 11.b, ''Time deposits of $100,000 or more''	Item 11.b, ''Time deposits of $250,000 or less''.
	Item 11.c, ''Time deposits of less than $100,000''	Item 11.c, ''Time deposits of more than $250,000''.
Schedule RI, Income Statement[9].	Item 2.a.(2)(b), Interest expense on ''Time deposits of $100,000 or more''.	Item 2.a.(2)(b), Interest expense on ''Time deposits of $250,000 or less''.
	Item 2.a.(2)(c), Interest expense on ''Time deposits of less than $100,000''.	Item 2.a.(2)(c), Interest expense on ''Time deposits of more than $250,000''.
Schedule RC–E, Deposit Liabilities.	Memorandum item 3.a, ''Time deposits of less than $100,000 with a remaining maturity or next repricing date of''.	Memorandum item 3.a, ''Time deposits of $250,000 or less with a remaining maturity or next repricing date of''.
	Memorandum item 3.b, ''Time deposits of less than $100,000 with a remaining maturity of one year or less''.	Memorandum item 3.b, ''Time deposits of $250,000 or less with a remaining maturity of one year or less''.
	Memorandum item 4.a, ''Time deposits of $100,000 or more with a remaining maturity or next repricing date of''.	Memorandum item 4.a, ''Time deposits of more than $250,000 with a remaining maturity or next repricing date of''.
	Memorandum item 4.b, ''Time deposits of $100,000 through $250,000 with a remaining maturity of one year or less''.	Memorandum item 4.b, ''Time deposits of more than $250,000 with a remaining maturity of one year or less''.
	Memorandum item 4.c, ''Time deposits of more than $250,000 with a remaining maturity of one year or less''	

The proposed changes to Schedules RC–K and RI would take effect March 31, 2016. The agencies are proposing to implement the changes to Schedule RC–E as of December 31, 2015, but comment is specifically requested on whether institutions' deposit recordkeeping systems will be able to support the proposed change in the reporting of maturity and repricing data in Memorandum items 3 and 4 as of that date.

2. Level of External Auditing Work Performed for the Reporting Institution During the Preceding Year

Each year in the March Call Report, each institution indicates in Schedule RC, Memorandum item 1, the most comprehensive level of auditing work performed by independent external auditors during the preceding calendar year for the institution or its parent holding company. In completing Memorandum item 1, each institution selects from nine statements describing a range of levels of auditing work the one statement that best describes the level of auditing work performed for it. Certain statements from which an institution must choose do not reflect current auditing practices performed in accordance with applicable standards and procedures promulgated by the U.S. auditing standard setters, namely the Public Company Accounting Oversight Board (PCAOB) and the Auditing Standards Board (ASB) of the American

[8] 79 FR 32172, June 4, 2014.

[9] The item numbers shown for Schedule RI are from the FFIEC 041 report form for institutions with domestic offices only. On the FFIEC 031 report form for institutions with domestic and foreign offices, the item numbers are items 2.a.(1)(b)(2) and 2.a.(1)(b)(3).

Institute of Certified Public Accountants. The PCAOB establishes auditing and related professional practice standards to be used in the performance and reporting of audits of the financial statements of public companies. The ASB establishes auditing, attestation, and quality control standards applicable to the performance and issuance of audit and attestation reports for entities that are not public companies, *e.g.* private companies.

The PCAOB's Auditing Standard No. 5 (AS 5), An Audit of Internal Control Over Financial Reporting That Is Integrated with An Audit of Financial Statements, became effective for fiscal years ending on or after November 15, 2007, and provides guidance regarding the integration of audits of internal control over financial reporting with audits of financial statements. To further emphasize the integration of these two audits, the PCAOB revised AS 5 in December 2010 by adding a statement that ''the auditor cannot audit internal control over financial reporting without also auditing the financial statements.'' Those public companies not required to undergo an audit of internal control over financial reporting must have an audit of their financial statements.

The ASB has separately provided similar guidance in Attestation Section 501 (AT 501), An Examination of an Entity's Internal Control over Financial Reporting That Is Integrated with an Audit of Its Financial Statements, which became effective for integrated audits for periods ending on or after December 15, 2008. Consistent with the PCAOB, the ASB states in AT 501 that ''[t]he examination of internal control should be integrated with an audit of financial statements'' and ''[a]n auditor should not accept an engagement to review an entity's internal control or a written assertion thereon.'' Under the ASB's previous attestation standards, an entity could engage an external auditor to examine and attest to the effectiveness of its internal control over financial reporting without auditing the entity's financial statements. Thus, at present, unless a private company is required to or elects to have an integrated internal control examination and financial statement audit, the private company may be required to or can choose to have an external auditor perform an audit of its financial statements, but it may not engage an external auditor to perform a standalone internal control examination.

The existing wording of statements 1, 2, and 3 of Schedule RC, Memorandum item 1, reads as follows:

1 = Independent audit of the bank conducted in accordance with generally accepted auditing standards by a certified public accounting firm which submits a report on the bank.

2 = Independent audit of the bank's parent holding company conducted in accordance with generally accepted auditing standards by a certified public accounting firm which submits a report on the consolidated holding company (but not on the bank separately).

3 = Attestation on bank management's assertion on the effectiveness of the bank's internal control over financial reporting by a certified public accounting firm.

Because these three statements no longer fully and properly describe the types of external auditing services performed for institutions or their parent holding companies under current professional standards and to enhance the information institutions provide the agencies annually about the level of auditing external work performed for them, the agencies are proposing to replace existing statements 1 and 2 with new statements 1a, 1b, 2a, and 2b and to eliminate existing statement 3 effective March 31, 2016. The revised statements would read as follows:

1a = An integrated audit of the reporting institution's financial statements and internal control over financial reporting conducted in accordance with the standards of the American Institute of Certified Public Accountants (AICPA) or the Public Company Accounting Oversight Board (PCAOB) by an independent public accountant that submits a report on the institution.

1b = An audit of the reporting institution's financial statements conducted in accordance with auditing standards of the AICPA or the PCAOB by an independent public accountant that submits a report on the institution.

2a = An integrated audit of the reporting institution's parent holding company's consolidated financial statements and internal control over financial reporting conducted in accordance with the standards of the AICPA or the PCAOB by an independent public accountant that submits a report on the consolidated holding company (but not on the institution separately).[10]

2b = An audit of the reporting institution's parent holding company's consolidated financial statements conducted in accordance with the auditing standards of the AICPA or the PCAOB by an independent public accountant that submits a report on the consolidated holding company (but not on the institution separately).

3. Chief Executive Officer Contact Information

All reporting institutions have been requested to provide ''Emergency Contact Information'' as part of their Call Report submissions since September 2002. This information request was added to the Call Report so that the agencies could distribute critical, time-sensitive information to emergency contacts at institutions should such a need arise. The primary contact should be a senior official of the institution who has decision-making authority. The primary contact may or may not be the institution's Chief Executive Officer (CEO). Information for a secondary contact also should be provided if such a person is available at an institution. The emergency contact information is for the confidential use of the agencies and is not released to the public.

The agencies periodically need to communicate with the CEOs of reporting institutions via email, but they currently do not have a complete list of CEO email addresses that would enable an agency to communicate directly to institutions' CEOs. The CEO communications are initiated or approved by persons at the agencies' senior management levels and would involve topics including new initiatives, policy notifications, and assessment information. For example, the FDIC initiates distributions of deposit insurance assessment notifications addressed to the CEOs of insured depository institutions, which are posted to each institution's FDICconnect account. However, in the absence of an up-to-date database of CEO email addresses that can be used for sending assessment notifications, the FDIC currently sends an email to each institution's FDICconnect user or users and requests that they download the notification and any attachments, and provide them to their CEO.

To streamline the agencies' CEO communication process, the agencies are proposing to request CEO contact information, including email addresses, in the Call Report separately from, but in a manner similar to, the currently

[10] The instructions for statement 2a would indicate this statement also applies to a reporting institution with $5 billion or more in total assets and a rating lower than 2 under the Uniform Financial Institutions Rating System that is required by Section 36(i)(1) of the Federal Deposit Insurance Act (12 U.S.C. 1831m(i)(1)) to have its internal control over financial reporting audited at the institution level, but undergoes a financial statement audit at the consolidated holding company level.

requested ''Emergency Contact Information'' beginning as of December 31, 2015. As with the ''Emergency Contact Information,'' the proposed CEO contact information would be for the confidential use of the agencies and would not be released to the public. The agencies intend for CEO email addresses to be used judiciously and only for significant matters requiring CEO-level attention. Having a comprehensive database of CEO contact information, including email addresses, would allow the agencies to communicate important and time-sensitive information directly to CEOs.

4. Reporting the Legal Entity Identifier

The Legal Entity Identifier (LEI) is a 20-digit alpha-numeric code that uniquely identifies entities that engage in financial transactions. The recent financial crisis spurred the development of a Global LEI System (GLEIS). Internationally, regulators and market participants have recognized the importance of the LEI as a key improvement in financial data systems. The Group of Twenty (G–20) nations directed the Financial Stability Board (FSB) to lead the coordination of international regulatory work and deliver concrete recommendations on the GLEIS by mid-2012, which in turn were endorsed by the G–20 later that same year. In January 2013, the LEI Regulatory Oversight Committee (ROC), including participation by regulators from around the world, was established to oversee the GLEIS on an interim basis. With the establishment of the full Global LEI Foundation in 2014, the ROC continues to review and develop broad policy standards for LEIs. The OCC, the Board, and the FDIC are all members of the ROC.

The LEI system is designed to facilitate several financial stability objectives, including the provision of higher quality and more accurate financial data. In the United States, the Financial Stability Oversight Council (FSOC) has recommended that regulators and market participants continue to work together to improve the quality and comprehensiveness of financial data both nationally and globally. In this regard, the FSOC also has recommended that its member agencies promote the use of the LEI in reporting requirements and rulemakings, where appropriate.[11]

Effective beginning October 31, 2014, the Board started requiring holding companies to provide their LEI on the cover pages of the FR Y–6, FR Y–7, and FR Y–10 reports[12] only if a holding company already has an LEI. Thus, if a reporting holding company does not have an LEI, it is not required to obtain one for purposes of these Board reports. Additionally, on July 2, 2015, the Board published in the **Federal Register** notice of final approval of a proposal to expand the collection of the LEI to all holding company subsidiary banking and nonbanking legal entities reportable on certain schedules of the FR Y–10 and in one section of the FR Y–6 and FR Y–7 if an LEI has already been issued for the reportable entity.[13] With respect to the Call Report, the agencies are proposing to have institutions provide their LEI on the cover page of the report beginning December 31, 2015, only if an institution already has an LEI. As with the Board reports, an institution that does not have an LEI would not be required to obtain one for purposes of reporting it on the Call Report.

5. Additional Preprinted Captions for Itemizing and Describing Components of Certain Items That Exceed Reporting Thresholds

As mentioned above in Section III.B, institutions are required to itemize and describe each component of certain items in five Call Report schedules when the component exceeds both a specified percentage of the item and a specified dollar amount. To simplify and streamline the reporting of these components and thereby reduce reporting burden, preprinted captions have been provided for those components of each of these items that, based on the agencies' review of the components previously reported for these items, institutions most frequently itemize and describe. When a preprinted caption is provided for a particular component of an item, an institution is not required to report the amount of that component when the amount falls below the applicable reporting thresholds.

Based on the most recent review of the component descriptions manually entered by reporting institutions because preprinted captions were not available, the agencies plan to add one new preprinted caption to Schedule RI–E, item 1, ''Other noninterest income,'' two new preprinted captions to Schedule RI–E, item 2, ''Other noninterest expense,'' and three new preprinted captions to Schedule RC–F, item 6, ''All other assets,'' effective December 31, 2015.[14] The introduction of these new preprinted captions is intended to simplify institutions' compliance with the requirement to itemize and describe those components of these items that exceed the applicable reporting thresholds (which are being proposed to be revised in Section II.B). The new preprinted caption for ''Other noninterest income'' is ''Income and fees from wire transfers.'' The two new preprinted captions for ''Other noninterest expense'' are ''Other real estate owned expenses'' and ''Insurance expenses (not included in employee benefits, premises and fixed assets expenses, and other real estate owned expenses).'' The three new preprinted captions for ''All other assets'' are ''Computer software,'' ''Accounts receivable,'' and ''Receivables from foreclosed government-guaranteed mortgage loans.''

6. Extraordinary Items

In January 2015, the FASB issued ASU No. 2015–01, ''Simplifying Income Statement Presentation by Eliminating the Concept of Extraordinary Items.'' This ASU eliminates the concept of extraordinary items from U.S. GAAP. At present, ASC Subtopic 225–20, Income Statement—Extraordinary and Unusual Items (formerly Accounting Principles Board Opinion No. 30, ''Reporting the Results of Operations''), requires an entity to separately classify, present, and disclose extraordinary events and transactions. An event or transaction is presumed to be an ordinary and usual activity of the reporting entity unless evidence clearly supports its classification as an extraordinary item. For Call Report purposes, if an event or transaction currently meets the criteria for extraordinary classification, an institution must segregate the extraordinary item from the results of its ordinary operations and report the extraordinary item in its income statement in Schedule RI, item 11, ''Extraordinary items and other adjustments, net of income taxes.''

ASU 2015–01 is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2015. Thus, for example, institutions with a calendar year fiscal year must begin to apply the ASU in their Call

[11] Financial Stability Oversight Council 2015 Annual Report, page 14 at (*http://www.treasury.gov/initiatives/fsoc/studies-reports/Documents/2015%20FSOC%20Annual%20Report.pdf*).

[12] FR Y–6, Annual Report of Holding Companies; FR Y–7, Annual Report of Foreign Banking Organizations; and FR Y–10, Report of Changes in Organizational Structure (OMB No. 7100–0297).

[13] 80 FR 38202.

[14] The addition of one of the new preprinted captions to Schedule RC–F, item 6, is based on the expected usage of a component resulting from the FASB's issuance of Accounting Standards Update (ASU) No. 2014–14, ''Classification of Certain Government-Guaranteed Mortgage Loans upon Foreclosure,'' that is in effect for certain institutions and will become effective for other institutions later in 2015 or in 2016 depending, in part, of their fiscal years.

Reports for March 31, 2016.[15] After an institution adopts ASU 2015–01, any event or transaction that would have met the criteria for extraordinary classification before the adoption of the ASU should be reported in Schedule RI, item 5.l, ''Other noninterest income,'' or item 7.d, ''Other noninterest expense,'' as appropriate, unless the event or transaction would otherwise be reportable in another item of Schedule RI.

Consistent with the elimination of the concept of extraordinary items in ASU 2015–01, the agencies plan to revise the instructions for Schedule RI, item 11, and remove the term ''extraordinary items'' from and revise the captions for Schedule RI, item 8, ''Income (loss) before income taxes and extraordinary items and other adjustments,'' item 10, ''Income (loss) before extraordinary items and other adjustments,'' and item 11, effective March 31, 2016. After the concept of extraordinary items has been eliminated and such items would no longer be reportable in Schedule RI, item 11, only the results of discontinued operations would be reportable in item 11.[16] Accordingly, effective March 31, 2016, the revised captions for Schedule RI, items 8, 10, and 11, would become ''Income (loss) before income taxes and discontinued operations,'' ''Income (loss) before discontinued operations,'' and ''Discontinued operations, net of applicable income taxes,'' respectively. Similarly, the caption for Schedule RI–E, item 3, would be changed from ''Extraordinary items and other adjustments and applicable income tax effect'' to ''Discontinued operations and applicable income tax effect.'' [17]

E. New and Revised Data Items of Limited Applicability

1. Changes to Schedule RC–Q, Assets and Liabilities Measured at Fair Value on a Recurring Basis

Schedule RC–Q is completed by institutions that had:

- Total assets of $500 million or more as of the beginning of their fiscal year; or
- Total assets of less than $500 million as of the beginning of their fiscal year and either:
  - Have elected to report financial instruments or servicing assets and liabilities at fair value under a fair value option with changes in fair value recognized in earnings, or
  - Are required to complete Schedule RC–D, Trading Assets and Liabilities.

Institutions required to complete Schedule RC–Q are currently required to treat securities they have elected to report at fair value under a fair value option as part of their trading securities. As a consequence, institutions must include fair value information for their fair value option securities, if any, in Schedule RC–Q two times: First, as part of the fair value information they report for their ''Other trading assets'' in item 5.b of the schedule, and then on a standalone basis in item 5.b.(1), ''Nontrading securities at fair value with changes in fair value reported in current earnings.'' This reporting treatment flows from the existing provision of the Glossary entry for ''Trading Account'' that, as discussed above, requires an institution that has elected to report securities at fair value under a fair value option to classify the securities as trading securities. However, as further discussed above, the agencies are proposing to remove this requirement because it is not consistent with current U.S. GAAP. As a result, an institution's fair value option securities can be classified as held-to-maturity, available-for-sale, or trading securities in accordance with the guidance in Topic 320, Investments-Debt and Equity Securities.

In its current form, Schedule RC–Q contains an item for available-for-sale securities along with the items identified above for ''Other trading assets,'' which includes securities designated as trading securities, and ''Nontrading securities at fair value with changes in fair value reported in current earnings.'' However, Schedule RC–Q does not include an item for held-to-maturity securities because, given the existing instructional requirements for fair value option securities, the held-to-maturity category includes only securities reported at amortized cost. By removing the requirement to report all fair value option securities within the scope of ASC Topic 320 as trading securities, as proposed earlier in this notice, the agencies are further proposing to replace item 5.b.(1) of Schedule RC–Q for nontrading securities accounted for under a fair value option with a new item for any ''Held-to-maturity securities'' to which a fair value option is applied. In this regard, existing item 1 for ''Available-for-sale securities'' would be renumbered as item 1.b and fair value information for any fair value option securities designated as ''Held-to-maturity securities'' would be reported in a new item 1.a of Schedule RC–Q. These changes to Schedule RC–Q would take effect December 31, 2015.

In addition, at present, institutions that have elected to measure loans (not held for trading) at fair value under a fair value option are required to report the fair value and unpaid principal balance of such loans in Memorandum items 10 and 11 of Schedule RC–C, Part I, Loans and Leases. Because Schedule RC–C, Part I, must be completed by all institutions, Memorandum items 10 and 11 also must be completed by all institutions although only a nominal number of institutions with less than $500 million in assets have disclosed reportable amounts for any of the categories of fair value option loans reported in the subitems of these two Memorandum items. Accordingly, the agencies are proposing to move Memorandum items 10 and 11 on the fair value and unpaid principal balance of fair value option loans from Schedule RC–C, Part I, to Schedule RC–Q effective December 31, 2015, and to designate them as Memorandum items 3 and 4. With only a limited number of institutions with less than $500 million in assets meeting the criteria for completing Schedule RC–Q, moving Memorandum items 10 and 11 from Schedule RC–C, Part I, to Schedule RC–Q should simplify Schedule RC–C, Part I, and thereby mitigate some of the reporting burden associated with Schedule RC–C, Part I.

2. Revisions to the Reporting of the Impact on Trading Revenues of Changes in Credit and Debit Valuation Adjustments by Institutions With Total Assets of $100 Billion or More

Institutions that reported average trading assets of $2 million or more for any quarter of the preceding calendar year must report a breakdown of their trading revenue (as reported in Schedule RI, item 5.c) by underlying risk exposure in Schedule RI, Memorandum items 8.a though 8.e. The five types of risk exposure are interest rate, foreign exchange, equity security and index, credit, and commodity and other. Institutions required to provide this five-way breakdown of their trading revenue that have $100 billion or more in total assets must also report the ''Impact on trading revenue of changes in the creditworthiness of the bank's derivative counterparties on the bank's derivative assets'' and the ''Impact on trading revenue of changes in the creditworthiness of the bank on the bank's derivative liabilities'' in

[15] Early adoption of ASU 2015–01 is permitted provided that the guidance is applied from the beginning of the fiscal year of adoption.

[16] The outdated reference to the reporting of the cumulative effect of certain changes in accounting principles in the instructions for item 11, which is inconsistent with the guidance in the Call Report Glossary entry for ''Accounting Changes,'' would be deleted from the instructions.

[17] Items 3.c.(1) and (2) also would be removed from Schedule RI–E.

Schedule RI, Memorandum items 8.f and 8.g, respectively. Memorandum items 8.f and 8.g were intended to capture the amounts included in trading revenue that resulted from calendar year-to-date changes in the reporting institution's credit valuation adjustments (CVA) and debit valuation adjustments (DVA).

The agencies have found inconsistent reporting of CVAs and DVAs by the institutions completing Memorandum items 8.f and 8.g of Schedule RI, which affects the analysis of reported trading revenues. Some institutions report CVAs and DVAs in these two items on a gross basis while other institutions report these adjustments on a net (of hedging) basis. Furthermore, at present, institutions may report a net CVA and DVA of hedges under only one of the five types of underlying risk exposures (*e.g.,* the overall net CVA and DVA amount is reported entirely with trading revenue from credit exposures) when the net CVA and net DVA should be properly allocated to each of the five different underlying types of risk exposures.

Consistent reporting of the impact on trading revenue from year-to-date changes in CVAs and DVAs is necessary to ensure the accuracy of the data available to examiners for planning and conducting safety and soundness examinations of institutions' trading activities and to the agencies for their analyses of derivatives and trading activities, and changes therein, at the industry and institution level. Furthermore, proper allocations of CVAs and DVAs (net of hedging) to the appropriate type of underlying risk exposure are necessary to avoid overstating the trading revenue from some types of underlying risk exposure and understating the trading revenue from other types, which may result in examiners and agency analysts reaching improper conclusions about the effectiveness of institutions' trading activities and their management of CVA and DVA risks.

To enhance the quality of the trading revenue information reported by the largest institutions in the U.S., promote consistency across institutions in the reporting of CVAs and DVAs, enable examiners to make more informed judgments about institutions' effectiveness in managing CVA and DVA risks, and provide a more complete picture of reported trading revenue, the agencies are proposing to replace existing Memorandum items 8.f and 8.g of Schedule RI with a tabular set of data items effective March 31, 2016. In this proposed table, those institutions that meet the criteria for completing these two Memorandum items (*i.e.,* institutions that reported average trading assets of $2 million or more for any quarter of the preceding calendar year and have $100 billion or more in total assets) would separately present their gross CVAs and DVAs (Memorandum items 8.f.(1) and 8.g.(1)) and any related CVA and DVA hedging results (Memorandum items 8.f.(2) and 8.g.(2)) by type of underlying risk exposure. The institutions also would report its gross trading revenue (Memorandum item 8.h) by type of underlying risk exposure before including positive or negative net CVAs and net DVAs (columns A through E). The sum of the amounts reported in Memorandum item 8.h, ''Gross trading revenue,'' plus the net CVA of hedges (the sum of columns A through E of Memorandum item 8.f.(1) minus the sum of columns A through E of Memorandum item 8.f.(2)), and plus the net DVA of hedges (the sum of the columns A through E of Memorandum item 8.g.(1) minus the sum of columns A through E of Memorandum item 8.g.(2)) must equal Schedule RI, item 5.c, ''Trading revenue.'' For purposes of this proposed tabular set of data items, the agencies are further proposing to require CVA and DVA amounts, as well as their hedges, to be allocated to the type of underlying risk exposure (*e.g.,* interest rates, foreign exchange, and equity) that gives rise to the CVA and the DVA.

In proposing that the institutions with assets of $100 billion or more report expanded information on the impact on trading revenues of changes in CVAs and DVAs, related hedging results, and gross trading revenues, the agencies request comment on the availability of these data by type of underlying risk exposure at those institutions that would be subject to this reporting requirement.

3. Dually Payable Deposits in Foreign Branches of U.S. Banks

Under the Federal Deposit Insurance Act (FDI Act), deposit obligations carried on the books and records of foreign branches of U.S. banks are not considered deposits, unless the funds are payable both in the foreign branch and at an office of the bank in the United States (that is, they are dually payable). In September 2013, the FDIC issued a final rule amending its deposit insurance regulations to clarify that deposits carried on the books and records of a foreign branch of a U.S. bank are not insured deposits even if they are made payable both at that branch and at an office of the bank in any state of the United States.[18] In addition, the final rule provides an exception for Overseas Military Banking Facilities operated under Department of Defense regulations.

The final rule does not affect the ability of a U.S. bank to make a foreign deposit dually payable. Should a bank do so, its foreign branch deposits would be treated as deposit liabilities under the FDI Act's depositor preference regime in the same way as, and on an equal footing with, domestic uninsured deposits. In general, ''depositor preference'' refers to a resolution distribution regime in which the claims of depositors have priority over (that is, are satisfied before) the claims of general unsecured creditors. Thus, if deposits held in foreign branches of U.S. banks located outside the United States are made dually payable, that is, made payable at both the foreign office and a branch of the bank located in the United States, the holders of such deposits would receive depositor preference in the event of the U.S. bank's failure.

To enable the FDIC to monitor the volume and trend of dually payable deposits in the foreign branches of U.S. banks, the agencies are proposing to add a new Memorandum item 2 to Schedule RC–E, Part II, on the FFIEC 031 Call Report effective December 31, 2015. The FFIEC 031 is applicable only to banks with foreign offices. The proposed new information on the amount of dually payable deposits at foreign branches of U.S. banks would enable the FDIC to determine, as required by statute, the least costly method of resolving a particular bank if it fails and the potential loss to the Deposit Insurance Fund. This requires the FDIC to plan for the distribution of the proceeds from the liquidation of the failed bank's assets, including consideration not only of insured deposits, but also other deposit liabilities for purposes of depositor preference, such as domestic uninsured deposits and dually payable deposits in foreign branches of the particular U.S. bank, which take priority over general unsecured liabilities.

4. Revisions To Implement the Supplementary Leverage Ratio for Advanced Approaches Institutions

Schedule RC–R, Part I, item 45, applies to the reporting of the supplementary leverage ratio (SLR) by advanced approaches institutions.[19] In

[18] See 78 FR 56583 (September 13, 2013).

[19] In general, an advanced approaches institution (i) has consolidated total assets (excluding assets held by an insurance underwriting subsidiary) on its most recent year-end regulatory report equal to $250 billion or more; (ii) has consolidated total on-balance sheet foreign exposure on its most recent

the sample Call Report forms and the Call Report instruction book for report dates before March 31, 2015, the caption for item 45 and the instructions for this item both indicated that, effective for report dates on or after January 1, 2015, advanced approaches institutions should begin to report their SLR in the Call Report as calculated for purposes of Schedule A, item 98, of the FFIEC 101, Regulatory Capital Reporting for Institutions Subject to the Advanced Capital Adequacy Framework.[20] However, the agencies temporarily suspended the collection of Schedule RC–R, Part I, item 45, before it took effect March 31, 2015, due to amendments to the SLR rule[21] and the need for updates to the associated SLR data collection in the FFIEC 101.

The agencies have finalized the most recent revisions to the SLR rule, which requires all advanced approaches institutions to disclose three items: the numerator of the SLR (Tier 1 capital, which is already reported in Call Report Schedule RC–R), the denominator of the SLR (total leverage exposure), and the ratio itself.[22] As part of the revisions to the FFIEC 101, the SLR section of the FFIEC 101 will apply only to top-tier advanced approaches institutions (generally, bank and savings and loan holding companies), and not to their subsidiary depository institutions. Therefore, lower tier advanced approaches depository institutions generally will not report SLR data in the FFIEC 101, and will need to do so in the Call Report, which would satisfy the SLR disclosure requirement in the revised SLR rule.[23]

Thus, the agencies are proposing to add a new item 45.a to Schedule RC–R, Part I, in which an advanced approaches depository institution (regardless of parallel run status) would report total leverage exposure as calculated under the agencies' SLR rule.

The agencies also are proposing to renumber current item 45 of Schedule RC–R, Part I, as item 45.b, to collect an institution's SLR. The ratio to be reported in item 45.b would equal Tier 1 capital reported on Schedule RC–R, Part I, item 26, divided by total leverage exposure reported in proposed item 45.a. Renumbered item 45.b would no longer reference the FFIEC 101 because lower tier depository institutions would no longer be calculating or reporting their SLRs on the FFIEC 101.

The reporting of the proposed SLR information would take effect March 31, 2016.

IV. Request for Comment

Public comment is requested on all aspects of this joint notice. Comments are invited on:

(a) Whether the proposed revisions to the collections of information that are the subject of this notice are necessary for the proper performance of the agencies' functions, including whether the information has practical utility;

(b) The accuracy of the agencies' estimates of the burden of the information collections as they are proposed to be revised, including the validity of the methodology and assumptions used;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected;

(d) Ways to minimize the burden of information collections on respondents, including through the use of automated collection techniques or other forms of information technology; and

(e) Estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Comments submitted in response to this joint notice will be shared among the agencies. All comments will become a matter of public record.

Dated: September 8, 2015.

Stuart Feldstein,

Director, Legislative and Regulatory Activities Division, Office of the Comptroller of the Currency.

Dated: September 11, 2015.

Michael Lewandowski,

Associate Secretary of the Board, Board of Governors of the Federal Reserve System.

Dated at Washington, DC, this 9th day of September, 2015.

Robert E. Feldman,

Executive Secretary, Federal Deposit Insurance Corporation.

[FR Doc. 2015–23402 Filed 9–17–15; 8:45 am]

BILLING CODE 4810–33P; 6210–01–P; 6714–01–P

year-end regulatory report equal to $10 billion or more (excluding exposures held by an insurance underwriting subsidiary); (iii) is a subsidiary of a depository institution that uses the advanced approaches to calculate its total risk-weighted assets; (iv) is a subsidiary of a bank holding company or savings and loan holding company that uses the advanced approaches to calculate its total risk-weighted assets; or (v) elects to use the advanced approaches to calculate its total risk-weighted assets.

[20] OMB numbers: For the OCC, 1557–0239; for the Board, 7100–0319; and for the FDIC, 3064–0159.

[21] See 79 FR 57725 (September 26, 2014). The amendments to the SLR rule took effect January 1, 2015.

[22] See 80 FR 41409 (July 15, 2015). The disclosure requirement is set forth in the agencies' regulatory capital rules (12 CFR 3.172 (OCC); 12 CFR 217.172 (Board), and 12 CFR 324.172 (FDIC)).

[23] Because certain depository institutions are exempt from filing the FFIEC 101, but must still report their SLR components and ratio, the agencies are proposing the depository institution-level collection of SLR data in the Call Report rather than in the FFIEC 101.

DEPARTMENT OF THE TREASURY

Office of the Comptroller of the Currency

Agency Information Collection Activities: Information Collection Renewal; Submission for OMB Review; Procedures To Enhance the Accuracy and Integrity of Information Furnished to Consumer Reporting Agencies Under the Fair and Accurate Credit Transactions Act

AGENCY: Office of the Comptroller of the Currency, Treasury.

ACTION: ACTION: Notice and request for comment.

SUMMARY: The OCC, as part of its continuing effort to reduce paperwork and respondent burden, invites the general public and other Federal agencies to take this opportunity to comment on a continuing information collection, as required by the Paperwork Reduction Act of 1995.

An agency may not conduct or sponsor, and a respondent is not required to respond to, an information collection unless it displays a currently valid OMB control number.

The OCC is soliciting comment concerning the renewal of its information collection titled, ''Procedures to Enhance the Accuracy and Integrity of Information Furnished to Consumer Reporting Agencies under the Fair and Accurate Credit Transactions Act (FACT Act).'' The OCC also is giving notice that it has sent the collection to OMB for review.

DATES: Comments must be received by October 19, 2015.

ADDRESSES: Because paper mail in the Washington, DC area and at the OCC is subject to delay, commenters are encouraged to submit comments by email, if possible. Comments may be sent to: Legislative and Regulatory Activities Division, Office of the Comptroller of the Currency, Attention: 1557–0238, 400 7th Street SW., Suite 3E–218, Mail Stop 9W–11, Washington, DC 20219. In addition, comments may be sent by fax to (571) 465–4326 or by electronic mail to *prainfo@occ.treas.gov.* You may personally inspect and photocopy comments at the OCC, 400 7th Street SW., Washington, DC 20219. For security reasons, the OCC requires that visitors make an appointment to inspect comments. You may do so by calling (202) 649–6700 or, for persons who are deaf or hard of hearing, TTY, (202) 649–5597. Upon arrival, visitors will be required to present valid government-issued photo identification and submit to security screening in order to inspect and photocopy comments.

All comments received, including attachments and other supporting materials, are part of the public record and subject to public disclosure. Do not include any information in your comment or supporting materials that you consider confidential or inappropriate for public disclosure.

Additionally, please send a copy of your comments by mail to: OCC Desk Officer, 1557–0238, U.S. Office of Management and Budget, 725 17th Street NW., #10235, Washington, DC 20503, or by email to: *oira submission@omb.eop.gov.*

FOR FURTHER INFORMATION CONTACT: Shaquita Merritt, OCC Clearance Officer, (202) 649–5490, for persons who are deaf or hard of hearing, TTY, (202) 649–5597, Legislative and Regulatory Activities Division, Office of the Comptroller of the Currency, 400 7th Street SW., Washington, DC 20219.

SUPPLEMENTARY INFORMATION: The OCC is requesting that OMB extend its approval of this collection of information.

Title: Procedures to Enhance the Accuracy and Integrity of Information Furnished to Consumer Reporting Agencies under Section 312 of the Fair and Accurate Credit Transactions Act (FACT Act).

OMB Control No.: 1557–0238.

Description: Section 312 of the Fair and Accurate Credit Transactions Act of 2003 (FACT Act) requires the issuance of (1) guidelines for use by furnishers regarding the accuracy and integrity of the information about consumers that they furnish to consumer reporting agencies and (2) regulations requiring furnishers to establish reasonable policies and procedures for implementing the guidelines. Section 312 also requires the issuance of regulations identifying the circumstances under which a furnisher must reinvestigate disputes about the accuracy of information contained in a consumer report based on a direct request from a consumer.

Twelve CFR 1022.42(a) requires furnishers to establish and implement reasonable written policies and procedures regarding the accuracy and integrity of consumer information that they provide to a consumer reporting agency (CRA).

Twelve CFR 1022.43(a) permits consumers to initiate disputes directly with the furnishers in certain circumstances. Furnishers are required to have procedures to ensure that disputes received directly from consumers are handled in a substantially similar manner to those complaints received through CRAs.

Twelve 1022.43(f)(2) incorporates the statutory requirement that a furnisher must notify a consumer by mail or other means (if authorized by the consumer) not later than five business days after making a determination that a dispute is frivolous or irrelevant. Twelve CFR 1022.43(f) incorporates the statute's content requirements for the notices.

Type of Review: Extension of a currently approved collection.

Affected Public: Businesses or other for-profit.

Estimated Number of Respondents: 1,464 respondents.

Estimated Total Annual Burden: 185,443 hours.

A 60-day **Federal Register** notice concerning this collection of information was published on July 7, 2015, 80 FR 38808. No comments were received. Comments continue to be invited on:

(a) Whether the collection of information is necessary for the proper performance of the functions of the OCC, including whether the information has practical utility;

(b) The accuracy of the OCC's estimate of the burden of the collection of information;

(c) Ways to enhance the quality, utility, and clarity of the information to be collected;

(d) Ways to minimize the burden of the collection on respondents, including through the use of automated collection techniques or other forms of information technology; and

(e) Estimates of capital or start-up costs and costs of operation, maintenance, and purchase of services to provide information.

Dated: September 14, 2015.

Mary H. Gottlieb,

Regulatory Specialist, Legislative and Regulatory Activities Division.

[FR Doc. 2015–23403 Filed 9–17–15; 8:45 am]

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DEPARTMENT OF THE TREASURY

Fiscal Service

Surety Companies Acceptable on Federal Bonds: Berkshire Hathaway Specialty Insurance Company

AGENCY: Bureau of the Fiscal Service, Fiscal Service, Department of the Treasury.

ACTION: Notice.

SUMMARY: This is Supplement No. 2 to the Treasury Department Circular 570, 2015 Revision, published July 1, 2015, at 80 FR 37735.

FOR FURTHER INFORMATION CONTACT: Surety Bond Branch at (202) 874–6850.

SUPPLEMENTARY INFORMATION: A Certificate of Authority as an acceptable surety on Federal bonds is hereby issued under 31 U.S.C. 9305 to the following company:

Berkshire Hathaway Specialty Insurance Company (NAIC # 22276).

BUSINESS ADDRESS: 3024 Harney Street, Omaha, NE., 68131–3580.

PHONE: (402) 916–3000.

UNDERWRITING LIMITATION b/: $323,414,000.

SURETY LICENSES c/: AL, AR, CO, FL, ID, IN, IA, ME, MD, MN, MT, NE., NJ, NC, ND, PA, RI, SD, TX, UT, VT,WV, WI, WY.

INCORPORATED IN: Nebraska.

Federal bond-approving officers should annotate their reference copies of the Treasury Circular 570 (''Circular''), 2015 Revision, to reflect this addition.

Certificates of Authority expire on June 30th each year, unless revoked prior to that date. The Certificates are subject to subsequent annual renewal as long as the companies remain qualified (*see* 31 CFR part 223). A list of qualified companies is published annually as of July 1st in the Circular, which outlines details as to the underwriting limitations, areas in which companies are licensed to transact surety business, and other information.

The Circular may be viewed and downloaded through the Internet at *http://www.fiscal.treasury.gov/fsreports/ref/suretyBnd/surety_home.htm.*

Questions concerning this notice may be directed to the U.S. Department of the Treasury, Bureau of the Fiscal Service, Surety Bond Branch, 3700 East-West Highway, Room 6D22, Hyattsville, MD 20782.

Dated: September 8, 2015.

Kevin McIntyre,

Manager, Financial Accounting and Services Branch, Bureau of the Fiscal Service.

[FR Doc. 2015–23446 Filed 9–17–15; 8:45 am]

BILLING CODE 4810–35–P

DEPARTMENT OF VETERANS AFFAIRS

Publication of Choice Act Section 201 Independent Assessments

AGENCY: Department of Veterans Affairs.

ACTION: Notice.

SUMMARY: The Department of Veterans Affairs (VA), the Commission on Care, the Senate Veterans' Affairs Committee, and the House Veterans' Affairs Committee have received the final report on the independent assessment of VA health care processes as required

under Section 201 of the Veterans Access, Choice, and Accountability Act of 2014 (VACAA). This Notice announces the public release of the report, entitled Independent Assessment of the Health Care Delivery Systems and Management Process of the Department of Veterans Affairs (Independent Assessment Report), on a VA Web site.

ADDRESSES: The complete copy of the final independent assessment is available on the following Web site: *http://www.va.gov/opa/choiceact/factsheets_and_details.asp.*

FOR FURTHER INFORMATION CONTACT: Dr. Regan Crump, Director, Office of Strategic Planning & Analysis, Veterans Health Administration, 810 Vermont Avenue NW., Washington, DC 20420, Telephone: (202) 461–7096 (This is not a toll-free number.)

SUPPLEMENTARY INFORMATION: VA entered into a contract with MITRE Corporation's Centers for Medicare and Medicaid Services' Alliance to Modernize Healthcare (CAMH), a private Federally Funded Research and Development Center (FFRDC) focused on large-scale transformation of health care systems in both the public and private sectors. CAMH and its partners have interviewed hundreds of VA and Veterans Health Administration (VHA) staff and visited 87 medical facilities across 30 states, Washington, DC, and Puerto Rico, as they conducted a comprehensive independent assessment of the hospital care, medical services, and other health care processes across VA medical facilities. VA has provided access to its data, systems, and records by sharing approximately 500 data sets, reports, and other critical documentation to assist with CAMH's comprehensive analysis.

The Commission on Care, an independent group of health care, business, and government experts established by VACAA, will now review this report and undertake a comprehensive evaluation and assessment of Veterans' access to VA health care and strategically examine how best to organize VHA to enable the delivery of high-quality and timely care. The Commission will submit a report of its findings and recommendations early in 2016 to the President of the United States through the Secretary of Veterans Affairs. VA will be required to implement each recommendation that the President considers feasible, advisable, and able to be implemented without further legislation.

Signing Authority

The Secretary of Veterans Affairs, or designee, approved this document and authorized the undersigned to sign and submit the Independent Assessment Report to the Office of the Federal Register for publication electronically as an official document of the Department of Veterans Affairs. Robert L. Nabors II, Chief of Staff, Department of Veterans Affairs, approved this document on September 15, 2015, for publication.

Dated: September 15, 2015.

William F. Russo,

Acting Director, Office of Regulation Policy & Management, U.S. Department of Veterans Affairs.

[FR Doc. 2015–23449 Filed 9–17–15; 8:45 am]

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FEDERAL REGISTER

Vol. 80 Friday,
No. 181 September 18, 2015

Part II

Environmental Protection Agency

40 CFR Parts 49, 51, 52, et al.
Oil and Natural Gas; Proposed Rules and Notice

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 49

[EPA–HQ–OAR–2014–0606; FRL–9931–75–OAR]

RIN 2060–AS27

Review of New Sources and Modifications in Indian Country: Federal Implementation Plan for Managing Air Emissions from True Minor Sources Engaged in Oil and Natural Gas Production in Indian Country

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The Environmental Protection Agency (EPA) is proposing a federal implementation plan (FIP) that would apply to new true minor sources and minor modifications at existing true minor sources in the production segment of the oil and natural gas sector that are locating or expanding in Indian reservations or in other areas of Indian country over which an Indian tribe, or the EPA, has demonstrated the tribe's jurisdiction. The FIP would satisfy the minor source permitting requirement under the ''Federal Minor New Source Review (NSR) Program in Indian Country'' (referred to as the ''Federal Indian Country Minor NSR rule''). The FIP proposes to require emission limitations and other requirements from certain federal emission standards as written at the time of construction or modification for compression ignition and spark ignition engines, compressors (reciprocating and centrifugal), fuel storage tanks, fugitive emissions from well sites and compressor stations, glycol dehydrators, hydraulically fractured oil and gas well completions, pneumatic controllers in production, pneumatic pumps, process heaters and storage vessels.

The EPA is also proposing several amendments to the Federal Indian Country Minor NSR rule, including adding new text regarding the purpose of the program, revising the program overview provision, establishing a compliance deadline of October 3, 2016, revising certain provisions to incorporate compliance with the FIP, revising the applicability provision to establish that sources are required to comply with the FIP unless they opt to obtain a source-specific permit or are otherwise required to obtain a source-specific permit, and revising the source registration provision. Also, we are revising the definition of Indian country to comport with a court decision that addressed EPA's jurisdiction to implement the Federal Indian Country Minor NSR rule: *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014). This court decision also affects the definition of Indian country under the Federal Major New Source Review Program in Indian Country so we are changing the definition under the Federal Indian Country Major NSR rule as well.

DATES: *Comments.* Comments must be received on or before November 17, 2015.

Public Hearing. The EPA will hold a public hearing on this proposed action. Details will be announced in a separate notice.

ADDRESSES: Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2014–0606, to the *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.,* on the web, cloud or other file sharing system). For additional submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Docket. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center (EPA/DC), Room 3334, EPA WJC West Building, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Mr. Christopher Stoneman, Outreach and Information Division, Office of Air Quality Planning and Standards (C–304–01), Environmental Protection Agency, Research Triangle Park, North Carolina, 27711, telephone number (919) 541–0823, facsimile number (919) 541–0072, email address: *stoneman.chris@epa.gov.* For questions about the oil and natural gas new source performance standards (NSPS) proposed action,[1] please contact Mr. Bruce Moore, Sector Policies and Programs Division, Office of Air Quality Planning and Standards (E–143–01), Environmental Protection Agency, Research Triangle Park, North Carolina, 27711, telephone number (919) 541–5460, facsimile number (919) 541–4312, email address: *moore.bruce@epa.gov.* For questions about the proposed action on the oil and natural gas source determination,[2] please contact Ms. Cheryl Vetter, Air Quality Policy Division, Office of Air Quality Planning and Standards (C504–03), Environmental Protection Agency, Research Triangle Park, North Carolina, 27711, telephone number (919) 541–4391, facsimile number (919) 541–541–4312, email address: *vetter.cheryl@epa.gov.* For questions about the applicability of this action to a particular source, please contact the appropriate EPA region:

- EPA Region 5 (Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin)—Ms. Genevieve Damico, Air Permits Section, Environmental Protection Agency, Region 5, Chicago, Illinois 60604; telephone (312) 353–4761; fax (312) 385–5501; email address: *damico.genevieve@epa.gov.*
- EPA Region 6 (Arkansas, Louisiana, New Mexico, Oklahoma, and Texas)—Ms. Bonnie Braganza, Air Permits Section, Multimedia Permitting and Planning Division, Environmental Protection Agency Region 6, Dallas, Texas 75202; telephone number (214) 665–7340; fax number (214) 665–6762; email address: *braganza.bonnie@epa.gov.*
- EPA Region 8 (Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming)—Ms. Claudia Smith, Air Program, Mail Code 8P–AR, Environmental Protection Agency Region 8, Denver, Colorado 80202;

[1] ''Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector,'' signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

[2] ''Source Determination for Certain Emission Units in the Oil and Natural Gas Sector,'' signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions/html.*

telephone number (303) 312–6520; fax number (303) 312–6520; email address: *smith.claudia@epa.gov.*

• EPA Region 9 (Arizona, California, Hawaii, Nevada, and Pacific Islands)—Ms. Lisa Beckham, Permits Office, Air Division, Air-3, Environmental Protection Agency Region 9, San Francisco, California 94105; telephone number (415) 972–3811; fax number (415) 947–3579; email address: *beckham.lisa@epa.gov.*

• All other EPA regions—The permit reviewer for minor sources in Indian country for your EPA region. You can find the list of the EPA permit reviewers at: *http://www.epa.gov/air/tribal/tribalnsr.html.* Scroll down to the heading, ''Existing Source Registration,'' and click on ''Reviewing Authority'' to access ''Environmental Protection Agency's Reviewing Authorities for Permits.''

SUPPLEMENTARY INFORMATION: The information presented in this preamble is organized as follows:

I. General Information
A. What entities are potentially affected by this proposal?
B. What should I consider as I prepare my comments to the EPA?
C. Where can I get a copy of this document and other related information?
II. Purpose
A. Proposed Oil and Natural Gas FIP
B. Proposed Amendments to the Federal Indian Country Minor NSR Rule
III. Background
A. Tribal Air Rule
B. Federal Indian Country Minor NSR Rule
C. General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country—Final Rules
D. EPA Actions Affecting Oil and Natural Gas Minor Sources in areas covered by the Federal Indian Country Minor NSR Rule
E. What is a FIP?
F. Oil and Natural Gas Sector
IV. Summary of Proposed Oil and Natural Gas FIP
A. Overview
B. What are the proposed FIP requirements?
C. Site-Specific Permits
V. Summary of Proposed Amendments to the Federal Indian Country Minor NSR Rule
VI. Implementation Issues
A. Requirements Relating to Threatened or Endangered Species and Historic Properties
B. What is the effect of this FIP on other Indian Country FIPs?
VII. Rationale for Proposed FIP
A. Why are we choosing a FIP as an alternative to site-specific permits, general permits and permits by rule?
B. How did we select which equipment to include in this proposed FIP?
C. Why are we excluding existing sources from this proposed oil and natural gas FIP?
D. Why is the EPA extending the permitting deadline for oil and natural gas true minor sources in areas covered by the Federal Indian Country Minor NSR rule?
VIII. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination with Indian Tribal Governments
G. Executive Order 13045: Protection of Children from Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions that Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act (NTTAA)
J. Executive Order 12898: Federal Actions to Address Environmental Justice in Minority Populations and Low-Income Populations

I. General Information

A. What entities are potentially affected by this proposal?

Entities potentially affected by this proposal consist of owners and operators of facilities included in the following source categories that are located, or planning to locate, in an Indian reservation or in another area of Indian country (as defined in 18 U.S.C. 1151) over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction where there is no EPA-approved program in place and that are subject to the requirements of the Federal Indian Country Minor NSR rule.

TABLE 1—SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION

Industry category	NAICS Code [a]	Examples of regulated entities/description of industry category
Oil and Gas Production/Operations	21111	Exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, desilting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property. Production of crude petroleum, the mining and extraction of oil from oil shale and oil sands, the production of natural gas, sulfur recovery from natural gas, and the recovery of hydrocarbon liquids from oil and gas field gases.
Crude Petroleum and Natural Gas Extraction	211111	Exploration, development and/or the production of petroleum or natural gas from wells in which the hydrocarbons will initially flow or can be produced using normal pumping techniques or production of crude petroleum from surface shales or tar sands or from reservoirs in which the hydrocarbons are semisolids.
Natural Gas Liquid Extraction	211112	Recovery of liquid hydrocarbons from oil and gas field gases; and sulfur recovery from natural gas.
Drilling Oil and Gas Wells	213111	Drilling oil and gas wells for others on a contract or fee basis, including spudding in, drilling in, redrilling, and directional drilling.

TABLE 1—SOURCE CATEGORIES AFFECTED BY THIS PROPOSED ACTION—Continued

Industry category	NAICS Code [a]	Examples of regulated entities/description of industry category
Support Activities for Oil and Gas Operations	213112	Performing support activities on a contract or fee basis for oil and gas operations (except site preparation and related construction activities) such as exploration (except geophysical surveying and mapping); excavating slush pits and cellars, well surveying; running, cutting, and pulling casings, tubes, and rods; cementing wells, shooting wells; perforating well casings; acidizing and chemically treating wells; and cleaning out, bailing, and swabbing wells.
Engines (Spark Ignition and Compression Ignition) for Electric Power Generation.	2211 **	Provision of electric power to support oil and natural gas production where access to the electric grid is unavailable.

[a] North American Industry Classification System.

This list is not intended to be exhaustive, but rather provides a guide for readers regarding entities likely to be potentially affected by this action. To determine whether your facility could be affected by this action, you should examine the applicability criteria in the final Federal Minor NSR Program in Indian Country (40 Code of Federal Regulations (CFR) 49.153), as well as the proposed FIP applicability in 40 CFR 49.101. If you have any questions regarding the applicability of this action to a particular entity, contact the appropriate person listed in the **FOR FURTHER INFORMATION CONTACT** section.

B. What should I consider as I prepare my comments to the EPA?

Submitting CBI. Do not submit this information to the EPA through regulations.gov or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD ROM that you mail to the EPA, mark the outside of the disk or CD ROM as CBI and then identify electronically within the disk or CD ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI to only the following address: Ms. Tiffany Purifoy, c/o OAQPS Document Control Officer (Mail Code C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2014–0606.

Coordination of Comments on Four Actions Affecting Oil and Natural Gas Sector. The EPA is proposing three rules that affect sources in the oil and natural gas sector. One is today's proposed rule, the oil and natural gas FIP for new true minor sources and minor modifications at existing true minor sources for Indian country. The other two proposed rules are the 2015 proposed 40 CFR part 60, subpart OOOOa rulemaking, which updates the oil and natural gas NSPS, and the proposed rule addressing oil and natural gas source determinations for NSR purposes.[3] In addition, the EPA is making available for public review and comment a draft Control Techniques Guidelines (CTG) for the Oil and Natural Gas Source Category document.[4] We welcome comments on all four of these actions. To help us respond more efficiently to public comments on this proposal, we request that commenters submit comments addressing the oil and natural gas NSPS signed on August 18, 2015 to the docket for the oil and natural gas NSPS, Docket ID No. EPA–HQ–OAR–2010–0505. Please do not send comments on the proposed oil and natural gas NSPS to the docket for this proposed FIP. Comments addressing the 2015 proposed oil and natural gas NSPS would include comments, for example, about the level of proposed control for the oil and natural gas NSPS. For this proposal, we request comments on the concept of relying on the oil and natural gas NSPS (and other applicable EPA rules) for the oil and natural gas FIP for Indian country. We request that comments on this concept and other comments applicable to this proposed FIP be submitted to the docket (Docket ID No. EPA–HQ–OAR–2014–0606). In addition, on September 18, 2015, the EPA proposed to amend 40 CFR parts 51, 52, 70, and 71 to address major source determinations for oil and gas extraction facilities for NSR purposes.[5] All comments related to source determinations for oil and gas extraction facilities should be addressed to Docket ID No. EPA–HQ–OAR–2013–0685. Finally, all comments on the draft oil and natural gas CTG document should be addressed to Docket ID No. EPA–HQ–OAR–2015–0216.

We have incorporated by reference Docket ID No. EPA–HQ–OAR–2010–0505 and Docket ID No. EPA–HQ–OAR–2013–0685 into DOCKET ID No. EPA–HQ–OAR–2014–0606. Comments submitted to Docket ID No. EPA–HQ–OAR–2010–0505 and Docket ID No. EPA–HQ–OAR–2013–0685 will be part of the official record for this oil and natural gas FIP proposed action.

Docket. The docket number for this action is Docket ID No. EPA–HQ–OAR–2014–0606.

World Wide Web (WWW). In addition to being available in the docket, an electronic copy of this document will be posted on the WWW. Following signature, the EPA will post a copy of this document at: *http://www.epa.gov/airquality/oilandgas/actions.html, http://www.epa.gov/nsr* (regulations and standards section of the NSR home page), and at: *http://www.epa.gov/air/tribal/tribalnsr.html* (tribal NSR page).

Preparing Comments. When submitting comments, remember to:

- Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).
- Respond to specific questions and link comments to specific CFR references when appropriate.
- Explain why you agree or disagree and suggest alternatives. Include specific regulatory text that implements your requested changes.

[3] "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources," signed August 18, 2015, and "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector," signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

[4] Draft Control Techniques Guidelines for the Oil and Natural Gas Source Category, signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

[5] "Source Determination for Certain Emission Units in the Oil and Natural Gas Sector," signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

• Explain technical information and/or data that you used to as the basis of your comment and provide references to the supporting information.

• If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

• Provide specific examples to illustrate your concerns and suggest alternatives.

• Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

• Make sure to submit your comments by the comment period deadline identified.

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this proposal will also be available on the WWW. Following signature by the EPA Administrator, a copy of this notice will be posted on the regulations and standards section of the NSR home page located at: *http://www.epa.gov/nsr,* on the tribal NSR page at: *http://www.epa.gov/air/tribal/tribalnsr.html,* and at the oil and natural gas air pollution standards page at *http://www.epa.gov/airquality/oilandgas/actions.html.*

II. Purpose

A. Proposed Oil and Natural Gas FIP

We are proposing a FIP for new true minor sources and minor modifications at existing true minor sources in the production segment of the oil and natural gas sector that are locating or expanding in an Indian reservation or in another area of Indian country over which a tribe, or the EPA, has demonstrated that the tribe has jurisdiction. The FIP would apply to new and modified true minor sources that are located or expanding in the referenced areas of Indian country designated as unclassifiable, attainment, or attainment/unclassifiable. It would not apply to new and modified true minor sources that are located or expanding in referenced areas of Indian country designated nonattainment. (Requirements for such areas would be addressed through site-specific minor NSR permitting and/or separate, reservation-specific FIPs.).

This FIP would be used instead of site-specific permits to fulfill the EPA's obligation under the Federal Indian Country Minor NSR rule to issue minor NSR preconstruction permits. The FIP would provide a streamlined, alternative approach addressing the permitting requirement, while also ensuring air quality protection through requirements that are unambiguous and legally and practicably enforceable. The FIP would reduce burden for sources and the Reviewing Authority and prevent delays in new construction due to the minor NSR permitting obligation. True minor sources in the oil and natural gas sector would be required to comply with the FIP instead of being required to obtain a minor source permit, unless a source chooses to opt out of the FIP and to obtain a site-specific minor NSR permit instead. In addition, the Reviewing Authority could require a source to obtain a site-specific permit based on local or reservation-specific air quality concerns where the emissions from the source could cause or contribute to a National Ambient Air Quality Standards (NAAQS) or increment violation. To protect the NAAQS, the Reviewing Authority could regulate emissions from operations at the minor source not regulated by the proposed FIP or could require more stringent emission limitations for operations at the source regulated by the proposed FIP.

In this FIP, we are proposing to require owners and operators of oil and natural gas production facilities to comply with six federal standards to reduce emissions of volatile organic compounds (VOC), nitrogen oxides (NO_X), sulfur dioxide (SO_2), particulate matter (PM, PM_{10}, $PM_{2.5}$), hydrogen sulfide (H_2S), carbon monoxide (CO) and various sulfur compounds from: compression ignition and spark ignition engines, compressors (reciprocating and centrifugal), fuel storage tanks, fugitive emissions from well sites and compressor stations, glycol dehydrators, hydraulically fractured oil and gas well completions, pneumatic controllers in production, pneumatic pumps, process heaters and storage vessels. The proposed oil and natural gas FIP requires compliance with four NSPS and two national emission standards for hazardous air pollutants (NESHAP). These rules are listed in Table 2.

TABLE 2—SIX FEDERAL RULES INCORPORATED BY REFERENCE IN THE PROPOSED OIL AND NATURAL GAS FIP FOR INDIAN COUNTRY [6]

40 CFR part and subpart	Title of subpart	Potentially affected sources in the production segment	Location
40 CFR part 63, subpart DDDDD	National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters.	Process heaters	*http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.14.63.ddddd&rgn=div6*
40 CFR part 60, subpart Kb	Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984.	Fuel Storage Tanks	*http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.k_0b&rgn=div6*
40 CFR part 60, subpart IIII	Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.	Compression Ignition Internal Combustion Engines.	*http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.iiii&rgn=div6*

[6] Two of the six rules are NESHAPs. Our basis for requiring compliance with NESHAPs in this rule that is designed to fulfill requirements of the Federal Indian Country Minor NSR rule is primarily to address criteria pollutants. These two NESHAPs control VOC and/or NO_X. VOC and NO_X are NSR-regulated pollutants of concern in the Federal Indian Country Minor NSR rule.

TABLE 2—SIX FEDERAL RULES INCORPORATED BY REFERENCE IN THE PROPOSED OIL AND NATURAL GAS FIP FOR INDIAN COUNTRY [6]—Continued

40 CFR part and subpart	Title of subpart	Potentially affected sources in the production segment	Location
40 CFR part 60, subpart JJJJ	Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.	Spark Ignition Internal Combustion Engines.	*http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.7.60.jjjj&rgn=div6*
40 CFR part 60, subpart OOOOa (proposed).	Standards for New and Modified Sources in the Oil and Natural Gas Sector.	Storage Vessels, Pneumatic Controllers, Compressors (Reciprocating and Centrifugal), Hydraulically Fractured Oil and Gas Well Completions, Pneumatic Pumps and Fugitive Emissions from Well Sites and Compressor Stations.	*http://www.epa.gov/airquality/oilandgas/actions.html*
40 CFR part 63, subpart HH	National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities.	Glycol Dehydrators	*http://www.ecfr.gov/cgi-bin/text-idx?SID=9f31077f895e9cb417f5386519941a47&mc=true&node=sp40.11.63.hh&rgn=div6*

For purposes of this FIP, we are proposing that compliance with these rules would effectively satisfy the NSR requirements. Therefore, we are proposing that true minor oil and natural gas sources subject to these standards must comply with these standards as they currently exist and as they may be amended, except for those provisions that we specifically exclude. (This proposed FIP does not change the applicability of the specified standards, nor does it relieve sources subject to the standards from complying with them, independently of this FIP.)

We are seeking comment on the concept of relying on these EPA standards as written at the time construction or modification of the source is begun for the requirements of the proposed oil and natural gas FIP. The purpose is to protect air quality in Indian reservations and in other areas of Indian country for which an Indian tribe, or the EPA, has demonstrated the tribe's jurisdiction and are designated as attainment, unclassifiable, or attainment/unclassifiable. It is our intent that oil and natural gas sources in areas covered by the Federal Indian Country Minor NSR rule using the proposed FIP would be subject, for purposes of the proposed FIP, to any amendments to an NSPS or NESHAP, including any amendments to the oil and natural gas NSPS that become part of the final oil and natural gas NSPS as a result of the 2015 proposed oil and natural gas NSPS.[7] Sources subject to this proposed FIP would be subject to any future changes made to these six underlying EPA standards only if they would otherwise be subject to those future changes. To help understand the requirements of this proposed oil and natural gas FIP, please see the 2015 proposed oil and natural gas NSPS and the provisions for each of the six federal rules (*i.e.,* four NSPS and two NESHAP) identified above.

B. Proposed Amendments to the Federal Indian Country Minor NSR Rule

Today's action proposes several amendments to the Federal Indian Country Minor NSR rule. First, we are proposing to revise § 49.151(b)(1) to establish as one of the purposes of the Federal Minor NSR Program in Indian Country the incorporation of the FIP (§§ 49.101 through 105) for oil and natural gas production true minor sources located in an Indian reservation or in another area of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction. Also, to clarify the purpose of subpart C, we are proposing to revise the subpart heading.

Second, we are proposing to revise § 49.151(c)(1)(iii)(A) to conform the registration deadline to the proposed, extended permitting deadline in § 49.151(c)(1)(iii)(B).

Third, we are proposing to revise § 49.151(c)(1)(iii)(B) to establish a deadline for when new and modified true minor sources in the production segment of the oil and natural gas sector that are located in an Indian reservation or in another area of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction or planning to locate in such areas must comply with the FIP in lieu of obtaining a minor NSR permit, unless the source opts for a site-specific minor NSR permit. If a source opts-out of the FIP, then we are proposing to extend the date for when the source must obtain a minor source permit. We are proposing to extend the deadline from March 2, 2016, to October 3, 2016.

Fourth, we are proposing to revise § 49.151(d)(1), (2) and (4) to incorporate compliance with the FIP.

Fifth, we are proposing to revise §§ 49.153(a)(1)(i)(B) and (ii)(B) to establish that oil and natural gas production true minor sources are required to comply with the FIP, unless a source opts out of the FIP pursuant to § 49.101(b)(2) or is required by the EPA to obtain a source-specific minor source permit pursuant to § 49.101(b)(3).

Sixth, we are proposing to revise §§ 49.160(c)(1)(ii) and (iii), to add § 49.160(c)(1)(iv) and to revise § 49.160(c)(4). We are revising § 49.160(c)(1)(ii) to conform the registration deadline to the extended permitting deadline in § 49.151(c)(1)(iii)(B). For § 49.160(c)(1)(iii) and § 49.160(c)(1)(iv), we are establishing that sources subject to the FIP still have to register with the Reviewing Authority, and we describe how to do that. For § 49.160(c)(4), we are proposing to clarify that submitting a registration form does not relieve a source of the requirement to comply with the FIP if the source (or any physical or operational change at the source) would be subject to any minor NSR rule.

Finally, we are revising the definition of Indian country in § 49.152(d) to comport with a court decision that

[7] "Oil and Natural Gas Sector: Emission Standards for New and Modified Sources," signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

addressed EPA's jurisdiction to implement the Federal Indian Country Minor NSR rule: *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014). This court decision also affects the definition of Indian country under the Federal Major New Source Review Program in Indian Country so we are changing the definition under the Federal Indian Country Major NSR rule in § 49.167.

III. Background

A. Tribal Authority Rule

Section 301(d) of the Clean Air Act (CAA) authorizes the EPA to treat Indian tribes in the same manner as states and directs the EPA to promulgate regulations specifying those provisions of the CAA for which such treatment is appropriate. (42 U.S.C.§ 7601(d)(1) and (2)). It also authorizes the EPA, in circumstances in which the EPA determines that the treatment of Indian tribes as identical to states is inappropriate or administratively infeasible, to provide by regulation other means by which the EPA will directly administer the CAA. (42 U.S.C. § 7601(d)(4)) Acting principally pursuant to that authority, on February 12, 1998,[8] the EPA promulgated what we refer to as the Tribal Authority Rule (TAR). (40 CFR 49.1–49.11). In the TAR, we determined that it was appropriate to treat tribes in the same manner as states for all CAA and regulatory purposes except a list of specified CAA provisions and implementing regulations thereunder. (40 CFR 49.4) Among those provisions of the CAA for which we determined that tribes will not be treated in the same manner as states are specific plan submittal and implementation deadlines for NAAQS-related requirements, including the requirement under section 110(a)(2)(c) to submit a program, including a permit program as required in parts C and D of the CAA, to regulate the modification and construction of any stationary source as necessary to assure that the NAAQS are achieved. In the TAR, we also determined that we would not treat tribes in the same manner as states with respect to CAA section 110(a)(1) (State Implementation Plan (SIP) submittal) and CAA section 110(c)(1) (directing the EPA to promulgate a FIP ''within 2 years'' after we find that a state has failed to submit a required plan, or has submitted an incomplete plan, or within 2 years after we disapproved all or a portion of a plan), among other provisions.[9]

The TAR preamble clarified that by including CAA section 110(c)(1) on the § 49.4 list, ''EPA is not relieved of its general obligation under the CAA to ensure the protection of air quality throughout the nation, including throughout Indian country. The preamble confirmed that the ''EPA will continue to be subject to the basic requirement to issue a FIP for affected tribal areas within some reasonable time.''[10] In the TAR, we thus exercised our discretionary authority under CAA §§ 301(a) and 301(d)(4) to establish a regulation providing that we would promulgate without unreasonable delay such FIP provisions as are necessary or appropriate to protect air quality (40 CFR 40.11(a)). Section 49.11(a) provides that the EPA will promulgate a FIP as necessary or appropriate to protect tribal air quality within a reasonable time if tribal efforts do not result in adoption and approval of tribal plans or programs.[11]

On August 21, 2006, acting pursuant to that authority, we proposed the regulation: ''Review of New Sources and Modifications in Indian Country'' (*i.e.,* Indian Country NSR rule).[12] Within this regulation, the EPA proposed to protect air quality in areas covered by the Federal Indian Country Minor NSR rule by establishing a FIP program to regulate the modification and construction of stationary sources consistent with the requirements of section 110(a)(2)(c) of the CAA. We call this part of the Indian Country NSR rule the Federal Indian Country Minor NSR rule. Under the Federal Indian Country Minor NSR rule, we proposed to provide a mechanism for issuing preconstruction permits for the construction of new minor sources and certain modifications of major and minor sources in areas covered by the Federal Indian Country Minor NSR rule. In developing the rule, the EPA conducted extensive outreach and consultation along with a 7-month public comment period that ended on March 20, 2007. The comments provided detailed information specific to Indian country and the final Federal Indian Country Minor NSR rule incorporated many of the suggestions we received. We promulgated final rules on July 1, 2011,[13] and the FIP became effective on August 30, 2011.

B. Federal Indian Country Minor NSR Rule

1. What is the Federal Indian Country Minor NSR Rule?

The Federal Indian Country Minor NSR rule applies to new and modified minor stationary sources and to minor modifications at existing major stationary sources located in Indian country[14] where there is no EPA-approved program in place. Tribes can elect to develop and implement their own EPA-approved program under the Tribal Authority Rule (TAR),[15] but they are not required to do so.[16] In the absence of an EPA-approved tribal program, the EPA implements the program. Alternatively, tribes can take administrative delegation of the federal program from the EPA and become the Reviewing Authority.

[8] ''Indian Tribes: Air Quality Planning and Management,'' U.S. Environmental Protection Agency, 63 FR 7254, February 12, 1998, *http://www.gpo.gov/fdsys/pkg/FR-1998-02-12/pdf/98-3451.pdf.*

[9] See 40 CFR 49.4(a) and (d) and 63 FR at 7262–66, February 12, 1998.

[10] See CAA section 301(a) and 63 FR at 7265, February 12, 1998.

[11] Section 49.11(a) states that the EPA, ''[s]hall promulgate without unreasonable delay such federal implementation plan provisions as are necessary or appropriate to protect air quality, consistent with the provisions of sections 301(a) and 301(d)(4), if a tribe does not submit a tribal implementation plan meeting the completeness criteria of 40 CFR part 51, Appendix V, or does not receive EPA approval of a submitted tribal implementation plan'' (see 40 CFR 49.11(a)).

[12] ''Review of New Sources and Modifications in Indian Country,'' U.S. Environmental Protection Agency, 71 FR 48696, August 21, 2006, *http://www.gpo.gov/fdsys/pkg/FR-2006-08-21/html/06-6926.htm.*

[13] ''Review of New Sources and Modifications in Indian Country,'' U.S. Environmental Protection Agency, 76 FR 38748, July 1, 2011, *https://www.federalregister.gov/articles/2011/07/01/2011-14981/review-of-new-sources-and-modifications-in-indian-country.*

[14] The Federal Indian Country Minor NSR rule defines ''Indian country'' to include three categories of lands consistent with 18 U.S.C. 1151, *i.e.,* Indian reservations, dependent Indian communities, and Indian allotments. The U.S. Court of Appeals for the District of Columbia Circuit vacated the rule with respect to non-reservation areas of Indian country (*i.e.,* dependent Indian communities and Indian allotments) (*Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014)). The court held that the state, not tribes or the EPA, has initial primary responsibility for implementation plans under CAA section 110 in non-reservation areas of Indian country in the absence of a demonstration of tribal jurisdiction by the EPA or a tribe. The rule, therefore, does not apply in non-reservation areas of Indian country unless a tribe or the EPA has demonstrated that a tribe has jurisdiction in a particular non-reservation area of Indian country.

[15] To be eligible to develop and implement an EPA-approved program, under the Tribal Authority Rule a tribe must meet four requirements: (1) Be a federally-recognized tribe; (2) have a functioning government carrying out substantial duties and powers; (3) propose to carry out functions pertaining to air resources of the reservation or other areas within the tribe's jurisdiction; and (4) be reasonably expected to be capable of carrying out the program. For more information go to: ''Indian Tribes: Air Quality Planning and Management,'' U.S. Environmental Protection Agency, 63 FR 7254, February 12, 1998, *http://www.gpo.gov/fdsys/pkg/FR-1998-02-12/pdf/98-3451.pdf.*

[16] Tribes can also establish permit fees under a tribal permitting program, as do most states.

Beginning September 2, 2014,[17] any new stationary source that will emit, or will have the potential to emit (PTE), a regulated NSR pollutant in amounts that will be: (a) Equal to or greater than the minor NSR thresholds, established in the Federal Indian Country Minor NSR rule; and (b) less than the amount that would qualify the source as a major source or a major modification for purposes of the Prevention of Significant Deterioration (PSD) or nonattainment major NSR programs, must apply for and obtain a minor NSR permit before beginning construction of the new source. Likewise, any existing stationary source (minor or major) must apply for and obtain a minor NSR permit before beginning construction of a physical or operational change that will increase the allowable emissions of the stationary source by more than the specified threshold amounts, if the change does not otherwise trigger the permitting requirements of the PSD or nonattainment major NSR program(s).[18]

In addition, among other things, the Federal Indian Country Minor NSR rule created a framework for the EPA to streamline the issuance of preconstruction permits to true minor sources by using general permits.

2. What are the minor NSR thresholds?

The ''minor NSR thresholds'' establish cutoff levels for each regulated NSR pollutant. If a source has a PTE in amounts lower than the thresholds, then it is exempt from the Federal Indian Country Minor NSR rule (see Table 3 and 40 CFR 49.153) for that pollutant. New or modified sources that have a PTE in amounts that are: (1) Equal to or greater than the minor NSR thresholds; and (2) less than the major NSR thresholds (generally 100 or 250 tons per year (tpy)) are ''minor sources'' of emissions and subject to the Federal Indian Country Minor NSR rule requirements at 40 CFR 49.151 through 161.

TABLE 3—MINOR NSR THRESHOLDS FOR SOURCES IN INDIAN COUNTRY [19]

Regulated NSR pollutant	Minor NSR thresholds for non-attainment areas tpy)	Minor NSR thresholds for attain-ment areas (tpy)
CO	5	10
NO_X	[20] 5	10
SO_2	5	10
VOC	[21] 2	5
PM	5	10
PM_{10}	1	5
$PM_{2.5}$	0.6	3
Lead	0.1	0.1
Fluorides	NA	1
Sulfuric acid mist	NA	2
H_2S	NA	2
Total reduced sulfur (including H_2S)	NA	2
Reduced sulfur compounds (including H_2S)	NA	2
Municipal waste combustor emissions	NA	2
Municipal solid waste landfill emissions (measured as nonmethane organic compounds)	NA	10

There may be sources that have emissions that are above the emission thresholds defined for a true minor source but which fall below the applicability levels for specific requirements referenced in the FIP. For example, the oil and natural gas sector NSPS, subpart OOOOa, includes a VOC threshold of 6 tpy for storage vessel applicability. In cases where a facility may have VOC emissions above 5 tpy but below 6 tpy, owners or operators would not be subject to the storage vessel provisions but would still be required under the proposed FIP to register with their appropriate regional office.

3. What is a true minor source?

''True minor source,'' under the Federal Indian Country Minor NSR rule, means a source that emits, or has the potential to emit, regulated NSR pollutants in amounts that are less than the major source thresholds under either the PSD Program at 40 CFR 52.21, or the Federal Major NSR Program for Nonattainment Areas in Indian Country at 40 CFR 49.166–49.173, but equal to or greater than the minor NSR thresholds in 40 CFR 49.153, without the need to take an enforceable restriction to reduce its PTE to such levels. A source's PTE includes fugitive emissions, to the extent that they are quantifiable, only if the source belongs to one of the 28 source categories listed in part 51, Appendix S, paragraph II.A.4(iii) or 40 CFR 52.21(b)(1)(iii), as applicable.

4. What is a general permit?

The Federal Indian Country Minor NSR rule specified the process and requirements for using general permits to authorize construction and modifications at true minor sources as a

[17] For oil and natural gas true minor sources, this date was extended to March 2, 2016. This notice proposes to extend it to October 3, 2016. For more information, see: ''Review of New Sources and Modifications in Indian Country Amendments to the Registration and Permitting Deadlines for True Minor Sources,'' 79 FR 34231, June 16, 2014, *http://www.gpo.gov/fdsys/pkg/FR-2014-06-16/pdf/2014-14030.pdf.*

[18] A source may, however, be subject to certain monitoring, recordkeeping and reporting (MRR) requirements under the major NSR programs, if the change has a reasonable possibility of resulting in a major modification. A source may be subject to both the Federal Indian Country Minor NSR rule and the reasonable possibility MRR requirements of the major NSR program(s).

[19] If part of a tribe's area of Indian country is designated as attainment and another part as nonattainment, the applicable threshold for a proposed source or modification is determined based on the designation where the source would be located. If the source straddles the two areas, the more stringent thresholds apply.

[20] In extreme ozone nonattainment areas, section 182(e)(2) of the CAA requires any change at a major source that results in any increase in emissions to be subject to major NSR permitting. In other words, any changes to existing major sources in extreme ozone nonattainment areas are subject to a ''0'' tpy threshold, but that threshold does not apply to minor sources.

[21] Id.

streamlined permitting approach. A general permit, for purposes of this action, is a permit document that contains standardized requirements that multiple stationary sources can use. The EPA may issue a general permit for categories of emission units or stationary sources that are similar in nature, have substantially similar emissions, and would be subject to the same or substantially similar permit requirements.[22] ''Similar in nature'' refers to size, processes, and operating conditions. The purpose of a general permit is to provide for protection of air quality, while simplifying the permitting process for similar minor sources. General permits offer a cost-effective means of issuing permits and provide a quicker and simpler mechanism for permitting minor sources than the site-specific permitting process.

5. What is a permit by rule?

Like a general permit, a permit by rule is a standard set of requirements that can apply to multiple stationary sources with similar emissions characteristics. For purposes of this action, a permit by rule would differ from a general permit in that the EPA would codify a permit by rule directly into the Federal Indian Country Minor NSR rule. The process for a source to obtain coverage under a permit by rule is more streamlined compared to a standard general permit, or a site-specific permit.

C. General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country—Final Rules

On May 1, 2015, the EPA published a final rule, ''General Permits and Permits by Rule for the Federal Minor NSR Program in Indian Country for Five Source Categories,'' to simplify the CAA permitting process for certain smaller sources of air pollution commonly found in Indian country.[23] In the action, the EPA finalized general permits for use in areas covered by the Federal Indian Country Minor NSR rule for new or modified minor sources in the following two source categories: Hot mix asphalt plants and stone quarrying, crushing and screening facilities. The EPA also finalized permits by rule for use in areas covered by the Federal Indian Country Minor NSR rule for new or modified minor sources in three source categories: Auto body repair and miscellaneous surface coating operations; gasoline dispensing facilities; and petroleum dry cleaning facilities. The EPA also took final action authorizing the use of general permits established under the program to create synthetic minor sources.

On July 17, 2014, the EPA published a proposed rule, ''General Permits and Permits by Rule for the Federal Minor NSR Program in Indian Country,'' to simplify the CAA permitting process for certain other smaller sources of air pollution commonly found in Indian country.[24] In the action, the EPA made available draft general permits for use in areas covered by the Federal Indian Country Minor NSR rule for new or modified minor sources in the following five source categories: Concrete batch plants; boilers; stationary spark ignition engines; stationary compression ignition engines; and sawmill facilities. The EPA also proposed a permit by rule for use in areas covered by the Federal Indian Country Minor NSR rule for new or modified minor sources in the graphic arts and printing operations source category.

D. EPA Actions Affecting Oil and Natural Gas Minor Sources in Areas Covered by the Federal Indian Country Minor NSR Rule

On January 14, 2014, the EPA published a proposed rule, ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country,''[25] that included two proposed amendments that affected true minor sources in the production segment of the oil and natural gas sector. The proposed amendments were: (1) The extension of the deadline by which new true minor sources and minor modifications of existing true minor sources in the production segment of the oil and natural gas sector must receive minor NSR permits prior to commencing construction, from September 2, 2014, to March 2, 2016; and (2) an adjustment to the deadline by which existing true minor sources in the production segment of the oil and natural gas sector must register, from September 2, 2014, to March 2, 2016. On June 16, 2014, the EPA finalized those amendments as proposed.[26]

On June 5, 2014, the EPA published an advance notice of proposed rulemaking (ANPR).[27] The purpose of the ANPR was to solicit broad feedback on the most effective and efficient means of implementing the Federal Minor NSR Program in Indian Country for sources in the production segment of the oil and natural gas sector. In it we discussed alternatives to site-specific permits for new and modified minor sources engaged in oil and natural gas production activities. The EPA requested comments on the alternative approaches and other aspects of managing air emissions from oil and natural gas sources in areas covered by the Federal Indian Country Minor NSR rule. The ANPR asked for public comment on: (1) The inclusion of existing minor source emissions in a FIP; (2) the advantages and disadvantages of available approaches (*i.e.,* FIP, permit by rule, or general permit) to manage emission impacts from the sources in the production segment of the oil and natural gas sector in areas covered by the Federal Indian Country Minor NSR rule; (3) the activities and pollutants that warrant regulation; (4) the coordination of compliance between any approach selected and the Federal Minor NSR Program in Indian Country; and (5) the appropriate emission control requirements.

We received 20 comments on the issues raised in the ANPR. Three comments were from tribes; one comment was from a federal government agency; three comments were from environmental groups; ten comments were from oil and natural gas companies or industry trade associations; and three comments were from anonymous commenters. The comments are summarized in a document entitled: ''Summary of Public Comments for Managing Emissions: Oil and Natural Gas Production in Indian Country'' and can be found in Docket ID

[22] ''Review of New Sources and Modifications in Indian Country,'' U.S. Environmental Protection Agency, 76 FR 38770, July 1, 2011, *https://www.federalregister.gov/articles/2011/07/01/2011–14981/review-of-new-sources-and-modifications-in-indian-country.*

[23] ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country for Five Source Categories,'' U.S. Environmental Protection Agency, 80 FR 25068, May 1, 2015, *http://www.gpo.gov/fdsys/pkg/FR–2015-05-01/pdf/FR-2015-05-01-FrontMatter.pdf.*

[24] ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country,'' 79 FR 41846, July 17, 2014, *http://www.gpo.gov/fdsys/pkg/FR-2014-07-17/pdf/2014-16814.pdf.*

[25] The ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country'' was proposed on January 14, 2014 (79 FR 2546). Proposed changes to the Federal Indian Country Minor NSR rule are on pages 79 FR 2570–2572. Electronic copies are available in the docket and in the regulations and standards section of our NSR home page located at *http://www.epa.gov/nsr.*

[26] For more information, see: ''Review of New Sources and Modifications in Indian Country Amendments to the Registration and Permitting Deadlines for True Minor Sources,'' 79 FR 34231, June 16, 2014, *http://www.gpo.gov/fdsys/pkg/FR-2014-06-16/pdf/2014-14030.pdf.*

[27] For more information, see: ''Managing Emissions from Oil and Natural Gas Production in Indian Country,'' 79 FR 32502, June 5, 2014, *http://www.gpo.gov/fdsys/pkg/FR-2014-06-05/pdf/2014-12951.pdf.*

No. EPA–HQ–OAR–2011–0151, which has been incorporated by reference into the docket for this action, Docket ID No. EPA–HQ–OAR–2014–0606.

We reviewed and carefully considered all the comments we received on the ANPR in developing this proposed FIP. Although not presented in a comment and response format, our consideration of the comments is evident throughout the discussions in this preamble. Commenters who wish their comments on the ANPR to also be considered in the development of the final FIP must resubmit those comments to the docket during the open public comment period for this proposed action.

On September 18, 2015, the EPA proposed updates to the NSPS for the oil and natural gas sector.[28] This proposed FIP adopts the standards from six federal rules, including the oil and natural gas NSPS (see Table 2). Future changes to these rules could affect requirements in the FIP because the proposed FIP adopts all or parts of these six federal emission standards, including future amendments. In addition, on September 18, 2015, the EPA proposed an oil and natural gas source determination rule.[29] This action is also connected to this FIP as it would affect how oil and natural gas sources are defined for the purpose of major/minor source determinations.

E. What is a FIP?

Under section 302(y) of the CAA, the term ''Federal implementation plan'' means ''. . . a plan (or portion thereof) promulgated by the Administrator to fill all or a portion of a gap or otherwise correct all or a portion of an inadequacy in a SIP, and which includes enforceable emission limitations or other control measures, means or techniques (including economic incentives, such as marketable permits or auctions of emission allowances), and provides for attainment of the relevant national ambient air quality standard.''

We interpret the reference to a ''gap'' in a SIP as including circumstances where a SIP does not apply (*i.e.,* on most Indian reservations and other areas of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction) and the relevant tribe has not implemented an EPA-approved plan. SIPs do not apply in these areas. In these circumstances, CAA §§ 301(a) and 301(d)(4) and 40 CFR 49.11(a) authorize the EPA to promulgate FIPs as are necessary or appropriate to protect air quality.

The Federal Indian Country Minor NSR rule is an example of a FIP. In that rule, we identified a regulatory gap that could have the effect of adversely impacting air quality due to the lack of approved minor NSR permit programs to regulate construction of new and modified minor sources and minor modifications of major sources in areas covered by the Federal Indian Country Minor NSR rule. The EPA promulgated the FIP to ensure that air resources in areas covered by the Federal Indian Country Minor NSR rule are protected by establishing a preconstruction permitting program to regulate emission increases resulting from construction and modification activities that are not already regulated by the major NSR permitting programs.

Because there are also no currently approved TIPs specifically applying to the issuance of general permits with respect to the reduction of emissions related to oil and natural gas production facilities, we believe a FIP is needed to protect air quality in areas covered by the Federal Indian Country Minor NSR rule. This proposed FIP would adopt legally and practicably enforceable requirements to control and reduce air emissions from oil and natural gas production. Therefore, in this rule, we propose to determine that it is necessary or appropriate to exercise our discretionary authority under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11(a) to promulgate a FIP to remedy an existing regulatory gap under the CAA with respect to oil and natural gas production operations in areas covered by the Federal Indian Country Minor NSR rule where there is no EPA-approved plan in place.

F. Oil and Natural Gas Sector

The oil and natural gas sector includes operations involved in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas.[30] Specifically for oil, the sector includes all operations from the well to the point of custody transfer to an oil transmission pipeline or other means of transportation to a petroleum refinery. For natural gas, the sector includes all operations from the well to the final end user. The oil and natural gas sector can generally be separated into four segments: (1) Oil and natural gas production; (2) natural gas processing; (3) natural gas transmission and storage; and (4) natural gas distribution.

The proposed oil and natural gas FIP focuses on the first segment, oil and natural gas production, because we believe the oil and natural gas production segment includes the majority of the true minor sources in the sector that would need to obtain a minor source permit in areas covered by the Federal Indian Country Minor NSR rule. The oil and natural gas production segment includes the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and natural gas dehydrators. Production operations also include the well drilling, completion and workover processes and include all the portable non-self-propelled apparatuses associated with those operations. Production sites include not only the sites where the wells themselves are located, but also include centralized gas and/or liquid gathering facilities where oil, condensate, produced water, and natural gas from several wells may be separated, stored, and treated. The production segment also includes the low to medium pressure, smaller diameter, gathering pipelines and related components that collect and transport the oil, natural gas and other materials and wastes from the wells or well pads.

The natural gas production segment ends where the natural gas enters a natural gas processing plant. In situations where there is no processing plant, the natural gas production segment ends at the point where the natural gas enters the transmission segment for long-line transport. The crude oil production segment ends at the storage and load-out terminal which is the point of custody transfer to an oil pipeline or for transport of the crude oil to a petroleum refinery via trucks or railcars. The petroleum refinery is not considered part of the oil and natural gas sector. Thus, with respect to crude oil, the oil and natural gas sector ends at point of custody transfer where crude oil enters an oil transmission pipeline or other means of transportation to a petroleum refinery.

Pollutants emitted from these activities that would be regulated through the proposed Federal Minor

[28] ''Oil and Natural Gas Sector: Emission Standards for New and Modified Sources,'' signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

[29] ''Source Determination for Certain Emission Units in the Oil and Natural Gas Sector,'' signed August 18, 2015, *http://www.epa.gov/airquality/oilandgas/actions.html.*

[30] For a more detailed discussion about the oil and natural gas sector, see the preamble to the ANPR at 79 FR 32505–32508, June 5, 2014.

NSR Program in Indian Country (regulated NSR pollutants) include: VOC, NO_X, SO_2, PM, PM_{10}, $PM_{2.5}$, H_2S, CO and various sulfur compounds. Hydrogen sulfide and SO_2 are emitted from production and processing operations that handle and treat sour gas.[31]

IV. Summary of Proposed Oil and Natural Gas FIP

A. Overview

This proposed oil and natural gas FIP would require owners and operators of new and modified existing minor sources in the oil and natural gas production segment that are located in areas covered by the Federal Indian Country Minor NSR rule to comply with six federal rules. One of the rules this FIP proposes to adopt is certain requirements of the proposed 40 CFR part 60, subpart OOOOa requirements.[32] Requirements under proposed NSPS, subpart OOOOa that have been proposed include those requirements that involve oil and natural gas production.[33]

These six rules are listed in Table 2 and provide requirements for:

- Storage vessels;
- Pneumatic controllers in production;
- Compressors (reciprocating and centrifugal);
- Hydraulically fractured oil and gas well completions;
- Pneumatic pumps;
- Fugitive emissions from well sites and compressor stations;
- Glycol dehydrators;
- Compression ignition and spark ignition engines;
- Fuel storage tanks; and
- Process heaters

The six rules and the provisions of each that the proposed oil and natural gas FIP would reference are discussed in more detail in this section. The proposed FIP requirements cover emission limitations and standards, monitoring, and testing and recordkeeping and reporting. For purposes of this FIP, we are proposing that true minor sources subject to these adopted standards must comply with these standards, as they currently exist or as amended in the future, except for those provisions that we specifically exclude under the FIP (unless the source opts-out of the FIP and obtains a source-specific permit). The excluded provisions are listed below. (This FIP does not change the applicability of the specified standards, nor does it relieve sources subject to the standards from complying with them, independently of this FIP.)

Also discussed in this section are proposed features of the FIP and proposed amendments to the Federal Indian Country Minor NSR rule.

B. What are the proposed FIP requirements?

We are proposing for purposes of this FIP, that owners and operators who determine that their new true minor source, or the modification of their existing true minor source, meets the applicability criteria of the proposed FIP must comply with all of the applicable and relevant requirements of the six federal rules listed in Table 2 above as written at the time construction or reconstruction of the source is begun, unless we exclude certain provisions as proposed below. In general, for this proposed FIP, we are proposing to exclude specific provisions of the rules because they are not relevant they would not apply to oil and natural gas production operations (*e.g.,* emission points at natural gas processing plants) or they apply only to manufacturers and not owner/operators.

For purposes of this FIP, we are proposing that true minor sources that are subject to 40 CFR part 63, subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters), must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun.

For purposes of this FIP, we are proposing that true minor sources that are subject to part 60, subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

- § 60.4200(a)(1)—Am I subject to this subpart? (applies to manufacturers);
- § 60.4200(b)—Not applicable to stationary ignition internal combustion engine being tested at an engine test cell/stand;
- § 60.4200(c)—Am I subject to this subpart? (area sources and exemptions from Title V permits);
- § 60.4201—What emission standards must I meet for non-emergency engines if I am a stationary compression ignition internal combustion engine manufacturer?;
- § 60.4202—What emission standards must I meet for emergency engines if I am a stationary compression ignition internal combustion engine manufacturer?;
- § 60.4203—How long must my engines meet the emission standards if I am a manufacturer of stationary compression ignition internal combustion engines?;
- § 60.4210—What are my compliance requirements if I am a stationary compression ignition internal combustion engine manufacturer?; and
- § 60.4215—What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

For purposes of this FIP, we are proposing that true minor sources that are subject to part 60, subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

- § 60.4230(b)—Not applicable to stationary spark ignition internal combustion engines being tested at an engine test cell/stand;
- § 60.4230(c)—Exemption for obtaining a Title V permit if owner or operator of an area source subject to this part;
- § 60.4231 and § 60.4232—Emission standards for manufacturers;
- § 60.4238 through § 60.4242—Compliance Requirements for Manufacturers; and
- § 60.4247—Mobile source provisions that apply to manufacturers of stationary spark ignition internal combustion engines or equipment containing such engines.

For purposes of this FIP, we are proposing that true minor sources that are subject to part 60, subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels, must comply with all of the provisions of the standard as written at the time

[31] Sour gas is natural gas with more than 5.7 milligrams of H_2S per normal cubic meters (0.25 grains/100 standard cubic feet), see AP–42 Compilation of Air Pollutant Emission Factors, Chapter 5.0 Introduction to Petroleum Industry, Section 5.3 Natural Gas Processing, available at: *http://www.epa.gov/ttnchie1/ap42/ch05/final/c05s03.pdf.*

[32] Proposed 40 CFR part 60, subpart OOOOa covers the emission sources covered under existing 40 CFR part 60, subpart OOOO, as well as adding coverage of new and modified emission sources beyond those covered in existing 40 CFR part 60, subpart OOOO. These additional sources are hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations.

[33] This list includes centrifugal compressors, reciprocating compressors, pneumatic controllers, pneumatic pumps, fugitive emissions from compressor stations, storage vessels. It excludes sources located in the transmission and storage segment because they are not part of this FIP proposal, which focusses on production.

construction or reconstruction of the source is begun, except for the following:

- § 60.112b(c)—Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia; and
- § 60.117b(a) and (b)—Delegation of authority.

For purposes of this FIP, we are proposing that true minor sources that are subject to proposed part 60, subpart OOOOa—Standards for New and Modified Sources in the Oil and Natural Gas Sector, must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

- § 60.5365a(f)(3)—Equipment exemption at processing plant;
- § 60.5365a(h)(4)—Existing sources constructed after August 23, 2011;
- § 60.5370a(c)—Permit exemption;
- § 60.5413a(a)(5)—Exemptions from performance testing—hazardous waste incinerator;
- § 60.5420a(a)(2)(i)—Advance notification requirements for well completions; and
- § 60.5420a(a)(2)(ii)—Advance notification requirements of well completions when subject to state regulation that requires advance notification.

For purposes of this FIP, we are proposing that true minor sources that are subject to 40 CFR part 63, subpart HH—NESHAP from Oil and Natural Gas Production Facilities, must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

- § 63.760(a)(2)—Facilities that process, upgrade or store hydrocarbon liquids;
- § 63.760(b)(1)(ii)—Each storage vessel with the potential for flash emissions;
- § 63.760(b)(1)(iii)—Equipment located at natural gas processing plants;
- § 63.760(g)—Recordkeeping for major sources that overlap with other regulations for equipment leaks;
- § 63.764(c)(2)–(3)—Requirements for compliance with standards for storage vessels and equipment at natural gas processing plants, respectively;
- § 63.766—Storage vessel standards; and
- § 63.769—Equipment leak standards.

Additionally, we are proposing that prior to beginning construction, under proposed § 49.104, true minor sources are required to address procedures for assessing threatened and endangered species and historic properties. The proposed section provides two options: (1) A site-specific National Environmental Policy Act (NEPA) process has been completed for the specific oil and natural gas activity, and the owner/operator also meets all air quality-related requirements as specified by the decision document (Record of Decision or Finding of No Significant Impact) for its NEPA analysis (these requirements are typically implemented and enforced as conditions of an approved Surface Use Plan of Operations and/or Application for Permit to Drill); or (2) submittal of documentation to the EPA Regional Office (and to the tribe where the source is located/locating) demonstrating that the source has completed the screening processes specified for consideration of threatened and endangered species and historic properties and received a determination from the EPA stating that it has satisfactorily completed these processes. (The processes are contained in the following document: ''Procedures to Address Threatened and Endangered Species and Historic Properties for New or Modified True Minor Oil and Natural Gas Production Sources in Indian Country Complying with the Oil and Natural Gas Minor Source Federal Implementation Plan,'' *http://www.epa.gov/air/tribal/tribalnsr.html*.)

C. Site-Specific Permits

We are proposing that owners and operators of new and modified true minor oil and natural gas sources that meet all of the following criteria must comply with the requirements contained in §§ 49.101 through 49.105 of this proposed FIP, unless the owner or operator opts-out of the FIP and instead obtains a site-specific permit per proposed §§ 49.101(b)(2) and (3):

- The facility is an oil and natural gas production facility as defined in proposed § 49.102;
- The oil and natural gas production facility is located in areas covered by the Federal Indian Country Minor NSR rule as defined in § 49.152(d) as proposed to be amended in this action;
- The oil and natural gas production facility is a new true minor source or a minor modification of an existing true minor source as determined under § 49.153;
- The oil and natural gas production facility begins construction or modification on or after October 3, 2016, the proposed extended permitting deadline date; and
- The oil and natural gas production facility is not located in a designated nonattainment area (the proposed FIP would only apply to minor sources in the oil and natural gas sector locating or expanding in areas designated as unclassifiable, attainment, or attainment/unclassifiable).

Sources covered by the Federal Indian Country Minor NSR rule that do not meet all of the criteria are, thus, not eligible to use the FIP and must, therefore, obtain a site-specific permit prior to beginning construction, on or after October 3, 2016.

If a source owner/operator does not want to comply with the FIP, they have the option to apply for a site-specific permit instead to meet the obligation under 40 CFR 49.151(c)(1)(iii)(B) of the Federal Indian Country Minor NSR rule to obtain a permit prior to commencing construction of a new true minor source or modification of an existing true minor source. As part of the FIP, we are proposing specific rule language in § 49.101(b)(2) to allow true minor sources proposing to construct on or after the proposed, extended deadline date of October 3, 2016, to opt-out of the default FIP if preferred by the owner or operator. We are proposing that an owner/operator of a source otherwise subject to the proposed FIP can opt out and seek a true minor source site-specific permit under 40 CFR 49.151(c)(1)(iii).

We are also proposing that the EPA, or other Reviewing Authority, may require owners or operators to obtain a site-specific permit in lieu of complying with the proposed FIP to ensure protection of the NAAQS. Under § 49.101(b)(3), we are proposing to specify that the Reviewing Authority may require an owner or operator of a source, in certain areas of Indian country proposing to construct on or after October 3, 2016, to apply for a site-specific permit for a new true minor source or minor modification of an existing true minor source. In particular, the Reviewing Authority may determine that the source is not sufficiently controlled under the proposed FIP to protect the NAAQS in the area of the proposed project (*e.g.,* if the measured design value for the area is close to or above the level of the NAAQS). In that circumstance, the Reviewing Authority can require the minor source to obtain a site-specific permit. The agency recommends at the time of registration, the owner/operator of all new sources or all sources scheduled for modification contact the Reviewing Authority for a review of the air quality status of that area, and the possibility of a requirement for a site specific permit.

V. Summary of Proposed Amendments to the Federal Indian Country Minor NSR Rule

Today's action proposes several amendments to the Federal Indian Country Minor NSR rule. First, we are proposing to revise § 49.151(b)(1) to add new text regarding the purpose of the Federal Minor NSR Program in Indian Country. The revised text indicates that the program satisfies the requirements of section 110(a)(2)(C) of the CAA by establishing a preconstruction permitting program for all new and modified minor sources (minor sources) and minor modifications at major sources located in Indian reservations and other areas of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction and where there is no EPA-approved plan in place and by establishing a FIP (§§ 49.101 to 49.105) for oil and natural gas production true minor sources located in such areas of Indian country.

Second, we are proposing to revise § 49.151(c)(1)(iii)(A) to conform the registration deadline to the proposed extended permitting deadline in § 49.151(c)(1)(iii)(B).

Third, we are proposing to revise § 49.151(c)(1)(iii)(B) to establish a deadline by which new and modified true minor sources in the oil and natural gas sector that are located in or plan to locate in Indian reservations or other areas of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction must comply with the FIP in lieu of obtaining a minor NSR permit (or obtain a minor source permit if the source opts out of the FIP). We are proposing to extend the permitting deadline from March 2, 2016, to October 3, 2016.

Fourth, we are proposing to revise § 49.151(d)(1), (2) and (4) to incorporate compliance with the FIP. We are proposing to revise § 49.151(d)(1) to indicate that if the owner/operator of a source begins construction of a new source or modification that is subject to this program after the applicable date (September 2, 2014, for all true minor sources, except oil and natural gas sources, and October 3, 2016, for oil and natural gas true minor sources) without applying for and receiving a permit pursuant to this program or complying with the FIP for oil and natural gas production, the owner/operator of the source will be subject to appropriate enforcement action. We are proposing to revise § 49.151(d)(2) to indicate that if you do not construct or operate your source or modification in accordance with the terms of your minor NSR permit or the FIP for oil and natural gas production, you source will be subject to appropriate enforcement action. We are proposing to revise § 49.151(d)(4) to indicate that issuance of a permit or compliance with the FIP for oil and natural gas production does not relieve the owner/operator of a source of the responsibility to comply fully with applicable provisions of any EPA-approved implementation plan or FIP or any other requirements under applicable law.

Fifth, we are proposing to revise §§ 49.153(a)(1)(i)(B) and (ii)(B) to establish that oil and natural gas true minor sources are required to comply with the FIP, unless the owner/operator of a source opts-out or is otherwise required by the EPA to obtain a minor source permit. Existing § 49.153(a)(1)(i)(B) requires the owner/operator of a new source to determine whether the source's PTE is equal to or greater than the corresponding minor NSR threshold. If it is, then the source is subject to the preconstruction requirements of the Federal Indian Country Minor NSR Permit rule for that pollutant. The proposed amendment adds a clause to the end of the paragraph stating that for oil and natural gas production sources, if the PTE for oil and natural gas production sources is equal to or greater than the corresponding minor NSR threshold, such sources shall instead comply with the requirements of proposed §§ 49.101 to 49.105, unless the owner/operator of the source opts-out of the FIP pursuant to proposed § 49.101(b)(2) or is required by the EPA to obtain a source-specific minor source permit pursuant to proposed § 49.101(b)(3).

Existing § 49.153(a)(1)(ii)(B) requires the owner/operator of modified sources to determine whether the increase in allowable emissions resulting from the modification would be equal to or greater than the minor NSR threshold for the pollutant being evaluated. If it is, the source is subject to the preconstruction requirements of the Federal Indian Country Minor NSR rule for that pollutant. The proposed amendment adds a clause to the end of the paragraph stating that, for oil and natural gas production sources, if the PTE for oil and natural gas production sources is equal to or greater than the corresponding minor NSR threshold, such sources shall instead comply with the requirements of proposed §§ 49.101 to 49.105, unless the owner/operator of the source opts-out of the proposed FIP pursuant to proposed § 49.101(b)(2) or is required by the EPA to obtain a minor source permit pursuant to proposed § 49.101(b)(3).

Sixth, we are proposing to revise §§ 49.160(c)(1)(ii) and (iii), to add § 49.160(c)(1)(iv) and to revise § 49.160(c)(4). For § 49.160(c)(1)(ii), we are proposing to conform the registration deadline to the proposed extended permitting deadline in § 49.151(c)(1)(iii)(B). For § 49.160(c)(1)(iii), we are proposing language to indicate that if your true minor source is an oil and natural gas source, and you commence construction or modification of your source on or after October 3, 2016, you must report your source's actual emissions (if available) as part of your permit application or registration of oil and natural gas production sources using a form provided by the EPA (''Registration for New Oil and Natural Gas Minor Sources and Minor Modifications at Existing True Minor Oil and Natural Gas Sources,'' *http://www.epa.gov/air/tribal/tribalnsr.html*). Your permit application or registration form for oil and natural gas production sources will be used to fulfill the registration requirements described in § 49.160(c)(2). This registration should occur each time an existing true minor source that would be subject to the proposed FIP undergoes a modification. For § 49.160(c)(1)(iv), we are proposing to add a paragraph indicating that sources subject to the proposed FIP must still satisfy the requirement to register under the Federal Indian Country Minor NSR rule by using the registration form provided by the EPA that is tailored to the oil and natural gas sector rather than a permit application. The registration form contains the information required in § 49.160(c)(2). After being reviewed by the permitting authority, completed registration forms will be available online on the EPA Regional Office Web sites. For § 49.160(c)(4), we are proposing to add language indicating that submitting a registration form does not relieve a source of the requirement to comply with the FIP for oil and natural gas production if the source or any physical or operational change at the source would be subject to any minor NSR rule.

Finally, we are proposing to revise the definition of Indian country in § 49.152 to comport with a court decision that addressed the EPA's authority to implement the Federal Indian Country Minor NSR rule in areas covered by the Federal Indian Country Minor NSR rule: *Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014). This court decision also affects the definition of Indian country under the Federal Major NSR Program in

Indian Country so we are changing the definition under the Federal Indian Country Major NSR rule § 49.167.

The Federal Indian Country Minor NSR rule and Federal Indian Country Major NSR rule currently define ''Indian country'' to include three categories of lands consistent with 18 U.S.C. 1151, *i.e.,* Indian reservations, dependent Indian communities, and Indian allotments. The U.S. Court of Appeals for the District of Columbia Circuit vacated the rule with respect to non-reservation areas of Indian country (*i.e.,* dependent Indian communities and Indian allotments) (*Oklahoma Dept. of Environmental Quality* v. *EPA,* 740 F.3d 185 (D.C. Cir. 2014)). The court held that the states, not tribes or the EPA, have initial primary responsibility for implementation plans under CAA section 110 in non-reservation areas of Indian country in the absence of a demonstration of tribal jurisdiction by the EPA or a tribe. We are proposing to revise the definition of Indian country in §§ 49.152(d) and 49.167 to add a clause indicating that, for purposes of the Federal Indian Country Minor NSR rule and the Federal Indian Country Major NSR rule, references to Indian country include all Indian reservation lands where no EPA-approved program is in place and all other areas of Indian country where no EPA-approved program is in place and over which an Indian tribe, or the EPA, has demonstrated that a tribe has jurisdiction.

These proposed changes will address the minor NSR permitting requirements for the affected sources, while reducing the permitting burden through a more efficient and effective means of implementing the requirements.

VI. Implementation Issues

A. Requirements Relating to Threatened or Endangered Species and Historic Properties

1. Overview

The Endangered Species Act (ESA) requires federal agencies to ensure, in consultation with the U.S. Fish and Wildlife Service and/or the National Marine Fisheries Service (the Services), that any action they authorize, fund, or carry out will not likely jeopardize the continued existence of any listed threatened or endangered species, or destroy or adversely modify the designated critical habitat of such species.

The National Historic Preservation Act (NHPA) requires federal agencies to take into account the effects of their undertakings on historic properties—*i.e.,* properties that are either listed on, or eligible for listing on, the National Register of Historic Places—and to provide the Advisory Council on Historic Preservation (the Council) a reasonable opportunity to comment on such undertakings.

In developing the proposed FIP, EPA has considered issues regarding listed species and historic properties and has included provisions designed to ensure appropriate review of potential impacts on the protected resources. Although the individual coverage of each source that would operate under the FIP would not constitute a separate triggering action for ESA or NHPA purposes, we believe that the proposed FIP's procedures relating to listed threatened or endangered species and historic properties provide an appropriate site-specific means of addressing issues regarding potential impacts on those resources in connection with sources that could be covered under the FIP. We have provided two options, as described below, for sources to meet the proposed FIP's requirements regarding these resources.

a. Sources for Which a Prior ESA and/or NHPA Assessment Has Been Completed

In most of Indian country, oil and natural gas production activities cannot begin before an owner/operator has obtained an approved application for permit to drill (APD). This authorization will include a National Environmental Policy Act Review (NEPA) [34] review that is typically provided by certain agencies within the U.S. Department of the Interior—the Bureau of Land Management (BLM) and the Bureau of Indian Affairs (BIA), (herein after referred to as ''Federal Land Managers (FLMs)'' for simplicity).[35] Under this review process, BLM is typically responsible for authorizing the mineral rights (*i.e.,* permission to produce oil and/or natural gas) and BIA for authorizing surface activities (*i.e.,* preparing the site for well-drilling activities and operating equipment for the production of oil and/or natural gas). (There are also cases where only one of these agencies will be involved or where another federal agency is involved as well.) Such APD authorizations are considered general triggering actions under the ESA and NHPA, and the FLMs will typically conduct review procedures to ensure that the requirements of these statutes are met. Frequently, these reviews occur in connection with an analysis performed by the appropriate FLM.[36]

Since an oil and gas exploration/production site involves surface activities and accessing the mineral resource below, thereby potentially requiring an approval from both BLM and BIA, these agencies often enter into agreements where one agency takes the lead in the overall NEPA (and associated ESA and NHPA) review process (*i.e.,* evaluations of the potential impacts regarding mineral rights and surface rights are combined). The lead agency may vary depending on the particular Indian reservation at issue. We believe that a majority of oil and gas activity in areas covered by the Federal Indian Country Minor NSR rule occurs on land within the jurisdiction of these agencies. This means that before an oil and natural gas owner/operator can begin construction under the FIP, the APD must be approved by the FLMs. As part of the NEPA review process, the following steps are generally performed:

- For the ESA, impacts to threatened and endangered species and critical habitats are assessed through interaction with local U.S. Fish and Wildlife Service field offices, with appropriate measures put in place to protect those resources. These conditions are incorporated in the FLMs' authorization.
- For the NHPA, impacts to historic properties are evaluated by interaction with State and/or Tribal Historic Preservation Offices. Approval of an action will address any appropriate measures needed to protect a historic property (*e.g.,* production equipment must be located a specified distance from a designated structure/road/etc.).

The assessment(s) conducted by the FLMs will likely consider a facility's air emissions with respect to well drilling, completion, well-pad construction activities and future operations and may require measures to reduce air emissions. In addition to any air pollution measures implemented through the FLM's NEPA (and associated ESA and NHPA) review, our proposed FIP would require each source to comply with the six federal rules listed in Table 2 above in order to protect ambient air quality. The measures employed under the proposed FIP would require compliance with specific requirements from the NSPS and NESHAP control requirements for the following emission points: compression ignition and spark ignition engines, compressors (reciprocating and centrifugal), fuel storage tanks, fugitive

[34] The NEPA regulatory requirements can be found at 40 CFR parts 1500–1508.

[35] The NEPA review process produces a decision document that is either a Record of Decision or a Finding of No Significant Impact.

[36] NEPA regulatory requirements can be found at 40 CFR parts 1500–1508.

emissions from well sites and compressor stations, glycol dehydrators, hydraulically fractured oil and gas well completions, pneumatic controllers in production, pneumatic pumps, process heaters and storage vessels. We believe the reductions achieved through the required emission controls, by virtue of being protective of ambient air quality, are also protective of threatened and endangered species, their habitats and historic properties.

Where the FLM(s) have concluded ESA and/or NHPA compliance as part of the APD process in connection with a particular source—whether as part of the FLM's NEPA review or otherwise—the source would be able to rely on that prior review for compliance with the proposed FIP's listed species (if prior ESA compliance has occurred) and historic properties (if prior NHPA compliance has occurred) requirements. No further assessment of impacts on these resources would be required by the proposed FIP as any such assessment would be duplicative of the prior work conducted by the FLM(s). We would require that documentation of completion of the APD process be provided before the owner/operator begins construction under the FIP.

b. Sources for Which No Prior ESA and/or NHPA Assessment Has Been Completed

For oil and natural gas production activities that do not undergo ESA and/or NHPA review as part of an authorization from the FLM(s), we propose that those facilities first complete screening procedures relevant to the particular resource that has not previously been reviewed before the owner/operator can begin construction under the proposed FIP. These screening procedures are similar to those currently in place for existing general permits and permits by rule in areas covered by the Federal Indian Country Minor NSR rule before the owner/operator can begin construction under the proposed FIP. Similar to our procedure for general permits and permits by rule, for the proposed FIP, once an owner/operator completes the screening procedures,[37] they would submit documentation to the EPA Regional Office and receive written verification of completion before beginning construction. As we explained in the development of both the general permits and permits by rule for the ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country,'' [38] to ensure listed species and critical habitats and historic properties are protected, we developed a framework for those permitting mechanisms requiring the source owner/operator to identify and assess potential effects to protected resources before obtaining coverage. Requiring this assessment aids in identifying any concerns related to potential impacts on listed species/critical habitat or historic properties early in the process when the greatest opportunities to mitigate or avoid any impacts—including changes to the facility's location or footprint—are available. The EPA believes that requiring a similar process in the air quality permit by rule, the general air quality permit, this proposed FIP and the general stormwater permits, will streamline the process for all concerned: the applicants, the EPA, the tribes, and the Services.

B. What is the effect of this proposed FIP on other Indian Country FIPs?

The objectives of this proposed FIP are to fulfill the requirements of the Federal Indian Country Minor NSR rule to address the air quality impacts of new and modified true minor sources and to impose appropriate air pollution control requirements that protect the NAAQS, while providing an alternative to obtaining preconstruction approval through the NSR preconstruction permitting process. This proposed FIP does not replace any other FIPs promulgated under the CAA for oil and natural gas sector sources in areas covered by the Federal Indian Country Minor NSR rule. An oil and natural gas source in areas covered by the Federal Indian Country Minor NSR rule that is subject to another CAA FIP must also comply with this proposed FIP. Generally, in cases where emission sources are already subject to a CAA FIP with more stringent requirements than those established for equivalent emission sources under this proposed FIP, the more stringent requirements supersede the requirements in this proposed FIP. Conversely, if requirements for certain emission sources in this proposed FIP are more stringent than requirements for equivalent emission sources in another applicable CAA FIP, then the requirements in this proposed FIP supersede the requirements for equivalent emission sources in the other FIP. In some cases, other applicable CAA FIPs defer to less stringent requirements in other federal CAA rules to avoid duplicative requirements. Those cases would provide an exception to this general concept.

In the case of the FIP for Oil and Natural Gas Well Production Facilities on the Fort Berthold Indian Reservation (FBIR FIP) at 40 CFR 49.4161–4168 (78 FR 17836), we stated in the preamble to that rulemaking that the FBIR FIP is not a permitting program and does not exempt facilities from any federal CAA permitting requirements, which would include compliance with this proposed FIP, and PSD preconstruction permitting requirements at 40 CFR 52.21, Federal Indian Country NSR permitting requirements for minor sources at 40 CFR 49.151, or federal Title V operating permit requirements at 40 CFR part 71. The FBIR FIP does provide legal and practical enforceability for the use of VOC emission controls, and compliant emission reductions achieved can be taken into account in calculating potential VOC emissions when determining the applicability of CAA permitting requirements. However, facilities subject to the FBIR FIP may emit VOCs from emission sources not regulated under the FBIR FIP, and/or may emit other NSR-regulated pollutants not regulated by the FBIR FIP at levels above the minor source thresholds in the Federal Indian Country Minor NSR rule or the major source PSD thresholds at 40 CFR 52.21, thus triggering NSR permitting requirements.

This proposed oil and natural gas FIP does not exempt facilities from complying with the FBIR FIP. The EPA recognizes that the VOC emission control requirements under the FBIR FIP are in some instances more stringent than the VOC emission reduction requirements of this proposed oil and natural gas FIP. For instance, the FBIR FIP requires up to 98 percent reduction of VOC emissions from storage tanks, while this proposed FIP, which relies on applicability under the 2015 proposed NSPS, subpart OOOOa, proposes to require 95 percent reduction of VOC emissions from storage vessels. To avoid duplicative requirements, the FBIR FIP specifies that facilities operating emission sources regulated under the FBIR FIP that are also subject to the storage vessel requirements under the 2015 proposed NSPS, subpart OOOOa, must comply with the applicable

[37] These procedures are available for sources potentially subject to this proposed FIP in a document entitled: ''Procedures to Address Threatened and Endangered Species and Historic Properties for New or Modified True Minor Oil and Natural Gas Production Sources in Indian Country Complying with the Oil and Natural Gas Minor Source Federal Implementation Plan,'' *http://www.epa.gov/air/tribal/tribalnsr.html.*

[38] ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country,'' 79 FR 2546, January 14, 2014, *http://www.gpo.gov/fdsys/pkg/FR-2014-01-14/pdf/2013-30345.pdf.*

requirements of the 2015 proposed NSPS, subpart OOOOa for those emission sources, rather than the requirements for produced oil and water storage tanks in the FBIR FIP. The FBIR FIP also regulates VOC emissions from oil and natural gas well completions, well casing heads, and heater treaters at oil and natural gas production facilities, which are not currently regulated by NSPS subpart OOOO, and, thus, are not part of this proposed FIP. Hydraulically fractured oil well completions were proposed for regulation in the 2015 proposed NSPS, subpart OOOOa signed on August 18, 2015. Therefore, a new or modified oil and natural gas well production facility that is subject to the FBIR FIP that would also be subject to this proposed FIP once final to meet the requirements of the Federal Indian Country Minor NSR rule would also need to comply with the FBIR FIP for casing head natural gas emissions and heater treater produced natural gas emissions.

VII. Rationale for Proposed FIP

A. Why are we choosing a FIP as an alternative to site-specific permits, general permits and permits by rule?

In the ANPR, we asked for comment on three alternatives to site-specific permits: general permits, permits by rule, and FIPs. Although commenters on the ANPR differed in their opinions on the best approach, the alternative approach garnering the most support was a FIP. Commenters supported using a FIP because it would streamline the permitting approach, eliminate the need for preconstruction approval from the permitting authority and apply requirements directly to sources. Commenters also supported a FIP because appropriate control measures would be in place and would provide the EPA and tribes assurances that construction and modification activities would be adequately and appropriately regulated. Some commenters supported a FIP because it could apply to existing sources. One commenter argued against a FIP approach because a FIP does not afford the same level of opportunity for a regulatory authority or the public to review, provide input on, or object to sources' coverage under a FIP as compared to a general permit.

We committed to developing an alternative to site-specific permits primarily to avoid delays in new construction due to our inability to process hundreds of true minor source permits in an acceptable timeframe. A FIP provides a regulatory tool that protects air quality, streamlines implementation and compliance assurance, and meets the EPA's obligation to permit minor NSR sources. The alternatives—site-specific permits, general permits and permits by rule—do not satisfy all of these concerns.

Both a general permit and a permit by rule provide a more streamlined approach for authorizing construction and modification of a source compared to site-specific permitting. A FIP, however, has the advantage of not requiring a source to initiate advance review and obtain approval of coverage from the Reviewing Authority before beginning construction (as would a general permit), and it would reduce the resource burden on reviewing authorities associated with processing the potentially large volume of requests from true minor sources in the oil and natural gas production segment for coverage under a general permit. So, from those standpoints a FIP is preferable to a general permit.

In comparison to a general permit, a FIP would provide less upfront scrutiny of an individual new construction or modification project and a citizen would not have the ability to object to a specific source gaining coverage. While we recognize these concerns, we believe that the proposed oil and natural gas FIP contains a robust set of emission control requirements and compliance monitoring and reporting provisions that will help ensure that a new or modified true minor source would not cause or contribute to a NAAQS or PSD increment violation.[39] In addition, any citizen could enforce the provisions of a FIP, as that person can with respect to requirements of any other implementation plan or CAA requirement, by commencing a civil action in the district court in the judicial district in which the source is located. Citizens retain the right under CAA section 304(a)(1) to commence a civil action ''against any person . . . who is alleged to have violated . . . or to be in violation of (A) an emission standard or limitation under this [Act] . . . .'' The Administrator also would retain the ability to enforce the requirements of a FIP under section 113(a)(1) of the CAA.

Another streamlined method, the permit by rule approach, also lacks the upfront scrutiny found with a general permit. In the first set of permits by rule that the EPA has issued for use in areas covered by the Federal Indian Country Minor NSR rule, we established the process for individual sources to obtain coverage under the EPA's permits by rule. It is a source notification process in which individual sources, unlike the general permit process, are not required to obtain the EPA's review and approval of a permit application prior to beginning construction.[40] In a manner similar to a FIP, a permit by rule establishes a set of requirements to which a source becomes subject when it obtains coverage under that permit by submitting a Notification of Coverage Form to the EPA, which the EPA then posts online. (For the sources subject to this proposed FIP, the EPA intends to post the registration forms that the EPA receives (see 40 CFR 49.160(c)). Thus, on the issue of public scrutiny, the FIP and the permit by rule approaches are essentially the same. The EPA prefers the FIP because it provides more certainty for affected sources than the permit by rule approach and, as discussed below, does not have any significant disadvantages as compared to the permit by rule approach.

Unlike NSR general permits and permits by rule, which cannot be used to address existing sources, a FIP could extend to existing sources; this is a key distinction between general permits and permits by rule versus a FIP. However, this proposal does not contain requirements for existing sources. The EPA's plan is to address existing sources, to the extent necessary, in the context of area- or reservation-specific FIPs designed to address areas or reservations with air quality issues (including nonattainment areas), as they arise, that are associated with oil and natural gas activities. Such FIP(s) will need to address, as necessary, requirements for existing sources, as well as additional requirements beyond those in this proposal for new and modified sources.

B. How did we select which equipment to include in this proposed FIP?

In determining which equipment to include in the proposed oil and natural gas FIP, we reviewed the EPA regulations that apply to emission units within the oil and natural gas production segment. We have relied substantially on analyses performed in support of the 2015 proposed NSPS, subpart OOOOa to help determine which emission units the EPA should consider regulating in the oil and natural gas sector in areas covered by the Federal Indian Country Minor NSR

[39] True minor sources in Indian country in the oil and natural gas sector are also required to register under 40 CFR 14.160 and provide certain information about their new or modified operations.

[40] ''General Permits and Permits by Rule for the Federal Minor New Source Review Program in Indian Country for Five Source Categories,'' U.S. Environmental Protection Agency, 80 FR 25068, May 1, 2015, *http://www.gpo.gov/fdsys/pkg/FR-2015-05-01/pdf/FR-2015-05-01-FrontMatter.pdf.*

rule as part of this proposed FIP.[41] In addition to the production segment sources proposed to be covered under NSPS, subpart OOOOa, in today's FIP, we are proposing requirements from existing EPA standards for three emission sources not covered by the NSPS, subpart OOOOa because they are present at oil and natural gas production sites and emit NO_X and/or VOC: engines, process heaters and glycol dehydration units. Three of the six federal rules listed in Table 2 above regulate these sources of pollution, among others. Therefore, we determined that a combination of existing federal regulations and the 2015 proposed NSPS, subpart OOOOa provides a comprehensive and consistent regulatory approach for addressing true minor oil and natural gas production sources in areas covered by the Federal Indian Country Minor NSR rule.

We have concluded that these federal regulations employ emission limitations that are technically and economically feasible, and cost effective because we have vetted the existing regulations via the public comment process and sources are currently complying with these federal standards, including new and modified sources in the oil and natural gas sector located in areas covered by the Federal Indian Country Minor NSR rule. The referenced NSPS are all promulgated pursuant to the EPA's authority under CAA section 111. Under CAA section 111(a), the emission limitations for all the affected sources, except process heaters and glycol dehydrators, ''reflect the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any non-air quality health and environmental impact and energy requirements) the Administrator determines have been adequately demonstrated.'' We refer to this level of control as the Best System of Emission Reduction (BSER). In determining BSER, we typically conduct a technology review that identifies what emission reduction systems exist and how much they reduce air pollution in practice. For each control system identified, we also evaluate its costs and other impacts.

The NESHAP for process heaters and glycol dehydrators are promulgated pursuant to the EPA's authority under CAA section 112. Under CAA section 112(d)(3), the emission limitations for glycol dehydrators and process heaters at major sources of hazardous air pollutants (HAPs) reflect MACT. The MACT emission limitation for new sources cannot be less stringent than the emission control achieved in practice by the best-controlled similar source, without considering costs. In addition, under CAA section 112(d)(5), the emission reduction requirements for triethylene glycol dehydrators at area sources reflect ''generally available control technology'' (GACT). For GACT there is no statutory minimum level of emissions reduction for new or existing sources and costs can be considered. We are proposing that the oil and natural gas FIP require sources to comply with the applicable MACT (for glycol dehydrators and process heaters located at major sources of HAP) or GACT (for glycol dehydrators located at area sources of HAP) emission limitations. Because the individual HAP pollutants regulated from glycol dehydrators by the NESHAP (and to some degree from process heaters, as well) for oil and gas production sources are also VOC, which are regulated NSR pollutants, the proposed FIP would create enforceable VOC reduction requirements for glycol dehydrators and process heaters. HAPs would serve as a surrogate for VOC with respect to emission limitations, monitoring, testing and compliance. In addition, compliance with 40 CFR part 63, subpart DDDDD MACT also provides beneficial reductions of non-targeted NSR pollutants, *i.e.,* NO_X.

The rationale supporting the applicability, emission limitations, monitoring, recordkeeping, reporting, and other provisions for each of the six federal rules is found in the preambles and background documents for those rulemakings. The six federal rules are available on the Electronic Code of Federal Regulations at: *http://www.ecfr.gov/cgi-bin/ECFR?page=browse.*

C. Why are we excluding existing sources from this proposed oil and natural gas FIP?

This section provides a brief overview of some of the significant comments on the inclusion of existing sources in a FIP, followed by a discussion of the EPA's rationale for why requirements for existing sources are not included in this proposed action. A complete summary of the comments on this and other issues we raised in the June 5, 2014, ANPR, can be found in Docket ID No. EPA–HQ–OAR–2011–0151, which has been incorporated by reference into the docket for this action, Docket ID No. EPA–HQ–OAR–2014–0606.

1. Comments in Favor of Regulation of Existing Sources

In response to the ANPR the EPA issued on June 5, 2014 (79 FR 32502), several commenters expressed support for the regulation of existing sources under a minor source permitting program (*i.e.,* a FIP) for oil and natural gas sources. Two commenters agreed with the ANPR that the cumulative impacts from existing sources could exceed that of large, new major sources. Some commenters voiced concerns about the impact of unregulated existing sources on the health and welfare of tribal members. One commenter asserted that there is substantial evidence demonstrating that existing oil and gas sources are responsible for considerable air pollution emissions within Indian country, noting that in response to the Federal Indian Country Minor NSR rule, Region 8 received approximately 6,300 registrations from existing minor sources in the oil and natural gas sector. The commenter asserted that regions like the Uintah Basin are already exceeding the ozone NAAQS, and even in regions where there are not yet NAAQS violations, emissions from oil and natural gas sources contribute to elevated ozone levels and HAP emissions. The commenter stated that the EPA's approach must reduce emissions from existing sources in order for the EPA to meet its duty to protect public health and welfare, in addition to improving visibility impairment and nitrogen deposition in national parks and wilderness areas. Another commenter indicated that they could provide modeling and monitoring data to the EPA demonstrating air quality impacts to the National Park System. One commenter also argued that requiring existing source controls would reduce methane emissions and subsequent climate impacts.

One commenter argued that the EPA must regulate existing sources to fulfill goals directed by the Obama administration, including recommendations from the Secretary of Energy's Advisory Board that ''measures should be taken to reduce emissions of air pollutants, ozone precursors, and methane as quickly as practicable.'' One commenter asserted that the EPA has the statutory authority to implement regulations for existing oil and natural gas sources. One commenter expressed support for regulating existing sources, but stated that not all existing minor sources should be regulated in the same manner. Other commenters indicated that cost-effective controls are available

[41] ''Background Technical Support Document for the Proposed New Source Performance Standards, 40 CFR part 60, subpart OOOOa,'' *http://www.epa.gov/airquality/oilandgas/actions.html.*

and should be applied to existing sources.

2. Comments in Opposition of Regulation of Existing Sources

In response to the ANPR the EPA issued on June 5, 2014 (79 FR 32502), many commenters objected to the regulation of existing sources. Commenters urged the EPA to prioritize development of a streamlined permitting process implementing the Federal Minor NSR Program in Indian Country and to not include existing sources. Several commenters provided legal arguments challenging the EPA's authority to impose requirements on existing sources. Two commenters stated that the EPA has not demonstrated that there is a need to regulate existing sources on a national basis. The commenter further argued that the EPA must make a much more definitive showing of adverse air quality impacts to justify existing source FIP requirements, taking into account the air quality, mix of emissions, and characteristics of each area in which it seeks to impose existing source controls.

Two commenters urged the EPA to develop an emissions inventory using emissions monitoring data prior to implementing a FIP. Five commenters asserted that the EPA must establish an attainment plan prior to regulating existing sources. The commenters urged that to regulate existing sources, the EPA must make a determination that regulation is needed to attain the NAAQS and develop an attainment plan for the nonattainment areas in which the sources are located, and only for the relevant nonattainment pollutants. Other commenters stated that the EPA must evaluate the need for any regulation of existing minor sources in each tribal area on a case-by-case basis.

3. The EPA's Approach in This Proposed Action on Existing Oil and Natural Gas Minor Sources in Indian Country

While the focus of the minor source permitting program is on new and modified oil and natural gas sources, the EPA believes that managing emissions from existing oil and natural gas sources in some areas of Indian country also may be important. This is because of the significant existing activity associated with the oil and natural gas sector in some areas of Indian country and the resultant need to protect public health and the environment from those emissions. Addressing existing sources through a FIP could be especially useful in areas of Indian country for which surrounding state requirements apply to existing oil and natural gas sources located on lands that are within a state's jurisdiction. In doing so, EPA would consider tribes' views and interests, including any interest in promoting economic development.

While EPA believes that it has the necessary authority to promulgate a FIP regulating existing sources, in this action, we are proposing a FIP that only applies to new and modified true minor sources in the production segment of the oil and natural gas sector. This proposed FIP for new and modified true minor sources in the oil and natural gas production segment locating or located in Indian reservations (and other areas of Indian country over which an Indian tribe, or the EPA, has demonstrated that the tribe has jurisdiction) would apply to all such areas designated attainment, unclassifiable, or attainment/unclassifiable. It would not apply to any areas designated nonattainment. The Federal Indian Country Minor NSR rule allows us to manage minor source emission increases in Indian country and to ensure that new emissions do not cause or contribute to a NAAQS or PSD increment violation. We are concerned that the rapid growth of the oil and natural gas production segment in combination with existing exploration and production activities, could result, or in some cases already has resulted, in adverse air quality impacts, especially in light of the approximately 6,300 existing true minor source registrations received in the EPA Region 8 Office for facilities in the oil and natural gas sector.[42] However, we believe that the most appropriate means for addressing impacts from existing sources is through area- or reservation-specific FIPs and not through this proposed, national FIP. If we determine that it is ''necessary or appropriate'' to exercise our discretionary authority under sections 301(a) and 301(d)(4) of the CAA and 40 CFR 49.11(a) of our implementing regulations, we will publish a proposed area- or reservation-specific FIP that provides an opportunity for full public review and comment. At a minimum, the EPA or tribes will need to develop area-specific plans if and when areas of Indian country become nonattainment for ozone or other NAAQS pollutants. At that time, any such area that has oil and natural gas minor source activity may require additional controls on existing (and new and modified) sources in order to achieve attainment of the NAAQS. One source of information for control options will be the EPA's CTGs for oil and natural gas activity that the EPA has made available for comment and will finalize in 2016.[43]

We believe that existing sources are best addressed through tailored, federal or tribal air quality plans because each basin producing oil and/or natural gas possesses different geological and meteorological characteristics and, thus, what primary fossil fuel resource is extracted can be very different in quality and type and the impacts from emissions associated with extraction activities can vary widely. For example, the predominant resource extracted from the Bakken Pool[44] is a light, volatile oil, while the primary resource extracted from the Uintah Basin is a heavy, thick oil. Each of these types, in many cases, call for different sets of control requirements that are best addressed through tailored plans versus a national FIP.

We believe that through tailored plans a number of cost-effective emission reduction measures could be applied to existing emission units to balance new growth by mitigating the potential for adverse air quality impacts from overall increases in emissions. A number of state air pollution control agencies already regulate some existing emissions from this segment.[45] For example, in February 2014, Colorado adopted additional regulations for oil and natural gas production operations that include such requirements as expanding nonattainment area pneumatic controller requirements statewide and reducing venting and flaring of gas streams at well sites, among other control strategies.[46] In addition, these regulations determined leak detection and repair monitoring to be cost effective at oil and natural gas production facilities. Some technologies may even provide the industry with cost savings due to recovered product. For example, the EPA's Natural Gas Star

[42] In the Federal Indian Country Minor NSR rule, EPA established a registration program that required owners and operators of existing true minor sources to file a one-time registration with the appropriate Reviewing Authority by March 1, 2013. The EPA's Region 8 Office has received about 6,300 registrations from true minor sources in the oil and natural gas sector. This far exceeded the amount received from sources in any other category.

[43] For more information, go to: *http://www.epa.gov/airquality/oilandgas/actions.html.*

[44] Bakken Pool means oil produced from the Bakken, Three Forks, and Sanish formations.

[45] See, *e.g.,* L. Gribovicz, WRAP, ''Analysis of States' and EPA Oil and Gas Air Emissions Control Requirements for Oil and Gas Emissions Control Requirements for Selected Basins in the Western United States (2013 Update),'' Nov. 8, 2013, available at *http://www.wrapair2.org/pdf/2013-11x_O&G%20Analysis%20(master%20w%20State%20Changes%2011-08).pdf.*

[46] See Colorado Dept. of Public Health and Environment, Air Quality Control Commission Web site at *http://www.colorado.gov/cs/Satellite/CDPHE-AQCC/CBON/1251647985820.*

program estimates that adding a vapor recovery unit to a storage tank could pay for itself in 3 to 37 months, and thereafter result in cost savings.[47]

D. Why is the EPA extending the permitting deadline for oil and natural gas true minor sources in areas covered by the Federal Indian Country Minor NSR rule?

The EPA is proposing to extend the deadline to allow us sufficient time to develop an approach for permitting new and modified true minor oil and natural gas production sources in areas covered by the Federal Indian Country Minor NSR rule that is consistent and coordinated with the EPA's overall approach to addressing emissions from this sector. Specifically, we have needed additional time to coordinate with the larger EPA effort to regulate methane and VOCs from the oil and natural gas sector. On January 14, 2015, as part of the Obama administration's methane strategy, the EPA outlined a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry, in order to ensure continued, safe and responsible growth in U.S. oil and natural gas production.[48] This commonsense strategy will reduce methane pollution from new sources in this rapidly growing industry, reduce ozone-forming pollutants from existing sources in areas that do not meet federal ozone health standards, and build on work that states and industry are doing to address emissions from existing sources elsewhere.

We intend to ensure the approach that we use to permit true minor oil and natural gas sources in areas covered by the Federal Indian Country Minor NSR rule reflects the EPA technical expertise gained through the work that has and will be done to understand feasible control opportunities in the oil and natural gas sector. In particular, we are drawing on the knowledge gained through the development of the technical white papers released on April 15, 2014, that address emerging data on VOCs and methane emissions from certain sources in the oil and natural gas sector, as well as techniques for mitigating those emissions.[49] The white papers, and the comments we received on them, are helping us better understand the sector, including sources located in Indian country. We are also considering in this action the comments provided in response to the ANPR (79 FR 32502, June 5, 2014) in which we sought feedback on the most effective and efficient means of implementing the Federal Minor NSR Program in Indian Country for sources in the oil and natural gas production segment of the oil and natural gas sector.

VIII. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is not a significant regulatory action and was, therefore, not submitted to the Office of Management and Budget for review.

B. Paperwork Reduction Act (PRA)

This action does not impose any new information collection burden under the PRA. OMB has previously approved the information collection activities contained in the existing regulations and has assigned OMB control number 2060–0003. This action merely proposes to establish a FIP which serves as a mechanism for true minor sources in the production segment of the oil and natural gas sector locating or located in areas covered by the Federal Indian Country Minor NSR rule to satisfy the requirements of the Federal Indian Country Minor NSR rule in lieu of obtaining a site-specific minor source permit. Because it is intended as a substitute for a site-specific permit which would contain information collection activities in the Information Collection Request for Federal Indian Country Minor NSR rule issued in July 2011, it would not impose any new obligations or enforceable duties on any state, local or tribal government or the private sector. In addition, the information collection activities contained in the 6 rules proposed to be part of the proposed FIP have also been previously approved by OMB.[50]

C. Regulatory Flexibility Act (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. The EPA analyzed the impact of streamlined permitting on small entities in the Federal Indian Country Minor NSR rule (76 FR 38748, July 1, 2011). The EPA determined that that action would not have a significant economic impact on a substantial number of small entities. This proposed action merely implements a particular aspect of the Federal Indian Country Minor NSR rule. We have, therefore, concluded that this action will have no net regulatory burden for all directly regulated small entities.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate, as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector. It simply provides one option for sources to comply with the Federal Indian Country Minor NSR rule. The Federal Indian Country Minor NSR rule itself imposes the obligation that true minor sources in areas covered by the Federal Indian Country Minor NSR rule obtain a minor source NSR permit and not this proposed FIP. This proposed FIP merely provides a vehicle for meeting that obligation.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It would not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

[47] See ''Lessons Learned from Natural Gas STAR Partners; Installing Vapor Recovery Units on Storage Tanks,'' available at *http://epa.gov/gasstar/documents/ll_final_vap.pdf* on the EPA's Natural Gas Star Web site: *http://epa.gov/gasstar/index.html*.

[48] For more information, go to: *http://www.epa.gov/airquality/oilandgas/pdfs/20150114fs.pdf*.

[49] The white papers can be found at: *http://www.epa.gov/airquality/oilandgas*.

[50] 40 CFR part 60, subpart Kb: Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984 (OMB Control No. 2060–0074); 40 CFR part 60, subpart IIII: Standards of Performance for Stationary Compression Ignition Internal Combustion Engines (OMB Control No. 2060–0590); 40 CFR part 60, subpart JJJJ: Standards of Performance for Stationary Spark Ignition Internal Combustion Engines (OMB Control No. 2060–0610); 40 CFR part 60, subpart OOOO: Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution (OMB Control No. 2060–0673); 40 CFR part 63, subpart DDDDD: National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters (OMB Control No. 2060–0616) and 40 CFR part 63, subpart HH: National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities (OMB Control No. 2060–0417).

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The EPA has conducted outreach on this rule via on-going monthly meetings with tribal environmental professionals in the development of this proposed action. This action reflects tribal comments on and priorities for developing an approach for permitting true minor sources in the production segment of the oil and natural gas sector in areas covered by the Federal Indian Country Minor NSR rule. The EPA offered consultation on the ANPR to elected tribal officials and the following tribes requested a consultation, which was held on July 18, 2014, with the tribes and/or their representatives: MHA (Mandan, Hidatsa and Arikara) Nations (Three Affiliated Tribes), Ute Tribe of the Uintah and Ouray Reservation, and Crow Nation.

At the consultation, the tribes present expressed a number of concerns regarding federal regulation of oil and natural gas activity in Indian country. Three main themes were expressed. First, the tribes expressed the concern that many areas of Indian country are facing difficult economic circumstances and are in need of economic development to improve the quality of life of tribal members; revenue from oil and natural gas activity in many areas provides that economic development. Second, in Indian country they indicated that oil and natural gas activity is already regulated by the federal government and that the EPA does not need to add to the burden. They expressed a wish to be able to manage their own resources without undue interference from the federal government. Finally, the tribes also expressed a need for greater resources so that they can implement their own environmental programs as they determine in their own lands.

We believe that the FIP is directly responsive to the first two issues in that, for attainment and related areas, we are proposing a FIP to fulfill our CAA responsibilities to protect air quality in Indian country in a manner that: (1) Does not create an uneven playing field with respect to federal requirements in adjacent states where oil and natural gas sources face the same EPA requirements; and (2) minimizes the processing burden on oil and natural gas sources. We will continue to provide outreach to tribal environmental professionals and offer to consult with tribal leadership on this proposed action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order (EO) 13045 because it is not economically significant as defined in EO 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children.

H. Executive Order 13211: Actions That Significantly Affect Energy Supply, Distribution, or Use

This action is not subject to Executive Order 13211, because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA)

This action does not involve technical standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. This proposed rule implements certain aspects of the Federal Indian Country Minor NSR rule.

Our primary goal in developing this program is to ensure that air resources in areas covered by the Federal Indian Country Minor NSR rule will be protected in the manner intended by the CAA. This action will help ensure air quality protection in areas covered by the Federal Indian Country Minor NSR rule, by including in a FIP a comprehensive set of control requirements for new and modified true minor source in the production segment of the oil and natural gas sector. In addition, through this proposed FIP, we seek to establish a mechanism that provides an effective and efficient method for implementing a preconstruction permitting program for true minor sources in areas covered by the Federal Indian Country Minor NSR rule that enables a streamlined process, which helps promote economic development by minimizing delays in new construction; and provides a process comparable to those programs operated outside of Indian county, which helps tribes compete for new oil and natural gas production in areas covered by the Federal Indian Country Minor NSR rule..

List of Subjects in 40 CFR Part 49

Environmental protection, Administrative practices and procedures, Air pollution control, Incorporation by reference, Indians, Indians-law, Indians-tribal government, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: August 18, 2015.

Gina McCarthy,

Administrator.

For the reasons set forth in the preamble, EPA proposes to amend 40 CFR part 49 as follows:

PART 49—INDIAN COUNTRY: AIR QUALITY PLANNING AND MANAGEMENT

■ 1. The authority citation for part 49 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 2. Subpart C of part 49 is amended by adding a new undesignated center heading and §§ 49.101 to 49.105 to read as follows:

Federal Implementation Plans for Tribes

Sec.
49.101 Introduction.
49.102 Definitions.
49.103 Delegation of authority of administration to Indian tribes.
49.104 Requirements regarding threatened or endangered species and historic properties.
49.105 Requirements.

Federal Implementation Plans for Tribes

§ 49.101 Introduction.

What is the purpose of §§ 49.101 through 49.105? (a) Sections 49.101 through 49.105 adopt legally and practicably enforceable requirements to control and reduce emissions of volatile organic compounds, nitrogen oxides, sulfur dioxide, particulate matter (PM, PM_{10}, $PM_{2.5}$), hydrogen sulfide, carbon monoxide and various sulfur compounds from oil and natural gas production segment operations.

(b) *Am I subject to §§ 49.101 through 49.105*? You are subject to the requirement if you meet the following criteria:

(1) Owners and operators of new true minor oil and natural gas sources or minor modifications at existing true minor oil and natural gas sources as determined pursuant to 40 CFR 49.153(a) that meet the criteria specified in paragraphs (b)(1)(i) through (b)(1)(v)

of this section, shall comply with the requirements of §§ 49.104 and 49.105, unless the owner or operator obtains a site-specific permit as specified in paragraph (b)(2) or (b)(3) of this paragraph.

(i) The facility is an oil and natural gas production facility as defined in § 49.102;

(ii) The oil and natural gas production facility is located in Indian country as defined in § 49.102;

(iii) The oil and natural gas production facility is a new true minor source or minor modification of an existing true minor source as determined under § 49.153;

(iv) The oil and natural gas production facility begins construction or modification on or after October 3, 2016; and

(v) The oil and natural gas production facility is not located in a designated nonattainment area.

(2) Owners and operators of facilities that meet the criteria specified in paragraphs (b)(1) of this section that choose to obtain a site-specific permit as specified in 40 CFR 49.155 before beginning construction are not required to comply with the requirements of §§ 49.101 to 49.105.

(3) Owners and operators of facilities that meet the criteria specified in paragraph (b)(1) of this section that the Reviewing Authority requires to obtain a site-specific permit to ensure protection of the NAAQS as specified in 40 CFR 49.155 before beginning construction are not required to comply with §§ 49.101 to 49.105.

(c) *When must I comply with §§ 49.101 through 49.105*? Compliance with §§ 49.101 through 49.101 is required on or after October 3, 2016.

§ 49.102 Definitions.

As used in §§ 49.101 through 49.105, all terms not defined herein shall have the meaning given them in the Clean Air Act, in subpart A, and subpart OOOOa of 40 CFR part 60, in the Prevention of Significant Deterioration regulations at 40 CFR 52.21, or in the Federal Minor NSR Program in Indian Country at 40 CFR 49.152. The following terms shall have the specific meanings given them:

Oil and natural gas production facility means a minor stationary source engaged in the extraction and production of oil and natural gas, as well as the processing, transmission and distribution of natural gas, including the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, and separation or treatment of oil and/or natural gas (including condensate). Oil and natural gas production components may include, but are not limited to: wells and related casing head; tubing head and ''Christmas tree'' piping; pumps; compressors; heater treaters; separators; storage vessels; pneumatic devices; natural gas dehydrators; well drilling, completion and workover processes and portable non-self-propelled apparatuses associated with those operations; and low to medium pressure, smaller diameter, gathering pipelines and related components that collect and transport the oil, natural gas and other materials and wastes from the wells or well pads.

Oil and natural gas well means a single well that extracts subsurface reservoir fluids containing a mixture of oil, natural gas, and water.

Owner or operator means any person who owns, leases, operates, controls, or supervises an oil and natural gas production facility.

Regional Administrator means the Regional Administrator of an EPA Region or an authorized representative of the Regional Administrator.

§ 49.103 Delegation of authority of administration to Indian tribes.

(a) *What is the purpose of this section*? The purpose of this section is to establish the process by which a Regional Administrator may delegate to a federally-recognized tribe the authority to assist the EPA with administration of this Federal Implementation Plan (§§ 49.101–49.105). This section provides for administrative delegation and does not affect the eligibility criteria under 40 CFR 49.6 for treatment in the same manner as a state or a tribe's ability to obtain approval of a tribal implementation plan under 40 CFR 49.7.

(b) *How does a tribe request delegation*? In order to be delegated authority to assist us with administration of this FIP, the authorized representative of a federally-recognized tribe must submit a request to a Regional

Administrator that:

(1) Identifies the specific provisions for which delegation is requested;

(2) Identifies the Indian Reservation or other areas of Indian country for which delegation is requested;

(3) Includes a statement by the applicant's legal counsel (or equivalent official) that includes the following information:

(i) A statement that the applicant is a tribe recognized by the Secretary of the Interior;

(ii) A descriptive statement that is consistent with the type of information described in § 49.7(a)(2) demonstrating that the applicant is currently carrying out substantial governmental duties and powers over a defined area;

(iii) A description of the laws of the tribe that provide adequate authority to administer the Federal rules and provisions for which delegation is requested; and

(iv) A demonstration that the tribal agency has the technical capability and adequate resources to administer the FIP provisions for which the delegation is requested.

(c) *How is the delegation of administrative authority accomplished*? (1) A Delegation of Authority Agreement will set forth the terms and conditions of the administrative delegation, will specify the rule and provisions that the tribe shall be authorized to implement on behalf of the EPA, and shall be entered into by the Regional Administrator and the tribe. The Agreement will become effective upon the date that both the Regional Administrator and the authorized representative of the tribe have signed the Agreement. Once the delegation becomes effective, the tribe will be responsible, to the extent specified in the Agreement, for assisting us with administration of this FIP and shall act as the Regional Administrator as that term is used in these regulations. Any Delegation of Authority Agreement will clarify the circumstances in which the term ''Regional Administrator'' found throughout this FIP is to refer only to the EPA Regional Administrator and when it is intended instead to refer to the EPA Regional Administrator or a federally-recognized tribe.

(2) A Delegation of Authority Agreement may be modified, amended, or revoked, in part or in whole, by the Regional Administrator after consultation with a tribe.

(d) *How will any Delegation of Authority Agreement be publicized*? The Regional Administrator shall publish a notice in the **Federal Register** informing the public of any Delegation of Authority Agreement with a tribe to assist us with administration of all or a portion of this FIP and will identify such delegation in the Code of Federal Regulations. The Regional Administrator shall also publish an announcement of the Delegation of Authority Agreement in local newspapers.

§ 49.104 Requirements regarding threatened or endangered species and historic properties.

(a) *What are sources required to do to address threatened or endangered species and historic properties*? An owner/operator required to meet the requirements contained in §§ 49.101 through 49.105 to satisfy its obligation under § 49.151(c)(1)(iii)(B) shall meet paragraph (a)(1) or (2) of this section.

(1) The owner/operator shall submit to the EPA Regional Office (and to the tribe where the source is located/locating) documentation demonstrating that prior Endangered Species Act (ESA) and/or National Historic Preservation Act (NHPA) compliance has been completed by another federal agency in connection with the specific oil and natural gas activity operated under this FIP. The owner/operator must be in compliance with all measures required as part of that prior ESA and/or NHPA process.

(2) The owner/operator shall submit to the EPA Regional Office (and to the tribe where the source is located/locating) documentation demonstrating that it has completed the screening procedures specified for consideration of threatened and endangered species and/or historic properties and receive written confirmation from the EPA stating that it has satisfactorily completed these procedures. The procedures document, ''Procedures to Address Threatened and Endangered Species and Historic Properties for New or Modified True Minor Oil and Natural Gas Production Sources in Indian Country Complying with the Oil and Natural Gas Minor Source Federal Implementation Plan,'' August 13, 2015, Version 1.0, is incorporated by reference into this section with the approval of the Director of the Federal Register under 5 U.S.C. 552(a) and 1 CFR part 51. To view or download the document, go to *http://www.epa.gov/air/tribal/pdfs/procedures_for_esa_and_nhpa_for_ong_sources_8-13-15.pdf.*

§ 49.105 Requirements.

(a) For true minor sources that are subject to 40 CFR part 63, subpart DDDDD (National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters), for purposes of this FIP, sources must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun.

(b) For true minor sources that are subject to 40 CFR part 60, subpart IIII—Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, for purposes of this FIP, sources must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

(1) § 60.4200(a)(1)—Am I subject to this subpart? (applies to manufacturers);

(2) § 60.4200(b)—Not applicable to stationary spark ignition internal combustion engines being tested at an engine test cell/stand;

(3) § 60.4200(c)—Am I subject to this subpart? (area sources and exemptions from Title V permits);

(4) § 60.4201—What emission standards must I meet for non-emergency engines if I am a stationary compression ignition internal combustion engine manufacturer?;

(5) § 60.4202—What emission standards must I meet for emergency engines if I am a stationary compression ignition internal combustion engine manufacturer?;

(6) § 60.4203—How long must my engines meet the emission standards if I am a manufacturer of stationary compression ignition internal combustion engines?;

(7) § 60.4210—What are my compliance requirements if I am a stationary compression ignition internal combustion engine manufacturer?; and

(8) § 60.4215—What requirements must I meet for engines used in Guam, American Samoa, or the Commonwealth of the Northern Mariana Islands?

(c) For true minor sources that are subject to 40 CFR part 60, subpart JJJJ—Standards of Performance for Stationary Spark Ignition Internal Combustion Engines, for purposes of this FIP, sources must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

(1) § 60.4230(b)—Not applicable to stationary spark ignition internal combustion engines being tested at an engine test cell/stand;

(2) § 60.4230(c)—Exemption for obtaining a Title V permit if owner or operator of an area source subject to this part;

(3) § 60.4231 and § 60.4232—Emission standards for manufacturers;

(4) § 60.4238 through § 60.4242—Compliance Requirements for Manufacturers; and

(5) § 60.4247—Mobile source provisions that apply to manufacturers of stationary spark ignition internal combustion engines or equipment containing such engines.

(d) For true minor sources that are subject to 40 CFR part 60, subpart Kb—Standards of Performance for Volatile Organic Liquid Storage Vessels, for purposes of this FIP, sources must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

(1) § 60.112b(c)—Site-specific standard for Merck & Co., Inc.'s Stonewall Plant in Elkton, Virginia; and

(2) § 60.117b(a) and (b)—Delegation of authority.

(e) For true minor sources that are subject to subpart OOOOa, Emission Standards for New and Modified Sources in the Oil and Natural Gas Sector, for purposes of this FIP, sources must comply with all of the provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

(1) § 60.5365a(f)(3)—Equipment exemption at processing plant;

(2) § 60.5365a(h)(4)—Existing sources constructed after August 23, 2011;

(3) § 60.5370a(c)—Permit exemption;

(4) § 60.5413a(a)(5)—Exemptions from performance testing—hazardous waste incinerator;

(5) § 60.5420a(a)(2)(i)—Advance notification requirements for well completions; and

(6) § 60.5420a(a)(2)(ii)—Advance notification requirements of well completions when subject to state regulation that requires advance notification.

(f) For true minor sources that are subject to 40 CFR part 63, subpart HH—National Emission Standards for Hazardous Air Pollutants from Oil and Natural Gas Production Facilities, for purposes of this FIP, sources must comply with all of the applicable provisions of the standard as written at the time construction or reconstruction of the source is begun, except for the following:

(1) § 63.760(a)(2)—Facilities that process, upgrade or store hydrocarbon liquids;

(2) § 63.760(b)(1)(ii)—Each storage vessel with the potential for flash emissions;

(3) § 63.760(b)(1)(iii)—Equipment located at natural gas processing plants;

(4) § 63.760(g)—Recordkeeping for major sources that overlap with other regulations for equipment leaks;

(5) § 63.764(c)(2)—(3)—Requirements for compliance with standards for storage vessels and equipment at natural gas processing plants, respectively;

(6) § 63.766 Storage vessel standards; and

(7) § 63.769 Equipment leak standards.

■ 3. Section 49.151 is amended by revising paragraphs (b)(1), (c)(1)(iii)(A) and (B), and (d)(1), (2) and (4) to read as follows:

§ 49.151 Program overview.

* * * * *

(b) * * *

(1) It satisfies the requirements of section110(a)(2)(C) of the Act by establishing a preconstruction permitting program for all new and modified minor sources (minor sources) and minor modifications at major sources located in Indian country and by establishing a Federal Implementation Plan (§§ 49.101 to 49.105) for oil and natural gas production true minor sources located in Indian country.

* * * * *

(c) * * *

(1) * * *

(iii) * * *

(A) If you own or operate an existing true minor source in Indian country (as defined in § 49.152(d)), you must register your source with the Reviewing Authority in your area by March 1, 2013. If your true minor source is not an oil and natural gas source, as defined in § 49.102, and you commence construction after August 30, 2011, and before September 2, 2014, you must also register your source with the Reviewing Authority in your area within 90 days after the source begins operation. If your true minor source is an oil and natural gas source, as defined in § 49.102, and you commence construction after August 30, 2011, and before October 3, 2016, you must register your source with the Reviewing Authority in your area within 90 days after the source begins operation. You are exempt from these registration requirements if your true minor source is subject to § 49.138.

(B) If your true minor source is not an oil and natural gas source, as defined in § 49.102, and you wish to begin construction of a new true minor source or a minor modification at an existing true minor source on or after September 2, 2014, you must first obtain a permit pursuant to §§ 49.154 and 49.155 (or a general permit/permit by rule pursuant to § 49.156, if applicable). If your true minor source is an oil and natural gas source, as defined in § 49.102, and you wish to begin construction of a new true minor source or a minor modification at an existing true minor source on or after October 3, 2016, you must either comply with the Federal Implementation Plan for oil and natural gas production sources located in Indian country (§§ 49.101 to 49.105) from the day you begin construction or opt out of those requirements pursuant to § 49.101(b)(2) and obtain a minor source permit pursuant to §§ 49.154 and 49.155 before beginning construction. Alternatively you may be required by the EPA, pursuant to § 49.101(b)(3), to obtain a minor source permit pursuant to §§ 49.154 and 49.155 before beginning construction. All proposed new sources or modifications are also subject to the registration requirements of § 49.160, except for sources that are subject to § 49.138.

* * * * *

(d) * * *

(1) If you begin construction of a new source or modification that is subject to this program after the applicable date specified in paragraph (c) of this section without applying for and receiving a permit pursuant to this program or complying with the Federal Implementation Plan at §§ 49.101 to 49.105 for oil and natural gas production, you will be subject to appropriate enforcement action.

(2) If you do not construct or operate your source or modification in accordance with the terms of your minor NSR permit or the Federal Implementation Plan for oil and natural gas production at §§ 49.101 to 49.105, you will be subject to appropriate enforcement action.

(3) * * *

(4) Issuance of a permit or compliance with the Federal Implementation Plan for oil and natural gas production at §§ 49.101 to 49.105 does not relieve you of the responsibility to comply fully with applicable provisions of any EPA-approved implementation plan or Federal Implementation Plan or any other requirements under applicable law.

* * * * *

■ 4. Section 49.152 is amended by revising the introductory text of paragraph (d) and adding paragraph (4) to the definition of ''Indian country'' to read as follows:

§ 49.152 Definitions.

* * * * *

(d) * * *

Indian country, as defined in 18 U.S.C. 1151, means the following as applied to this program:

* * * * *

(4) For purposes of this rule, references to Indian country include all Indian reservation lands where no EPA-approved program is in place and all other areas of Indian country where no EPA-approved program is in place and over which an Indian tribe, or the EPA, has demonstrated that a tribe has jurisdiction.

* * * * *

■ 5. Section 49.153 is amended by revising paragraphs (a)(1)(i)(B) and (a)(1)(ii)(B) to read as follows:

§ 49.153 Applicability.

* * * * *

(a)* * *

(1) * * *

(i) * * *

(B) *Step 2.* Determine whether your proposed source's potential to emit for the pollutant that you are evaluating, (including fugitive emissions, to the extent they are quantifiable, only if the source belongs to one of the source categories listed pursuant to section 302(j) of the Act), is equal to or greater than the corresponding minor NSR threshold in Table 1 of this section. If it is, you are subject to the preconstruction requirements of this program for that pollutant, except that oil and natural gas production sources shall instead comply with the requirements of the Federal Implementation Plan at §§ 49.101 to 49.105, unless you opt-out of the Federal Implementation Plan pursuant to § 49.101(b)(2) in which case you are subject to the preconstruction requirements of this program for that pollutant or are required by the EPA to obtain a minor source permit pursuant to § 49.101(b)(3). If not, go to Step 3 (paragraph (a)(1)(ii)(C) of this section).

(ii) * * *

(B) *Step 2.* Determine whether the increase in allowable emissions from the proposed modification (calculated using the procedures of paragraph (b) of this section) would be equal to or greater than the minor NSR threshold in Table 1 of this section for the pollutant that you are evaluating. If it is, you are subject to the preconstruction requirements of this program for that pollutant, except oil and natural gas production sources shall instead comply with the requirements of the Federal Implementation Plan at §§ 49.101 to 49.105, unless you opt-out of the Federal Implementation Plan pursuant to § 49.101(b)(2) in which case you are subject to the preconstruction requirements of this program for that pollutant or are required by the EPA to obtain a minor source permit pursuant to § 49.101(b)(3). If not, go to Step 3 (paragraph (a)(1)(ii)(C) of this section).

* * * * *

■ 6. Section 49.160 is amended by revising paragraphs (c)(1)(ii) and (iii), adding paragraph (c)(1)(iv) and revising paragraph (c)(4) to read as follows:

§ 49.160 Registration program for minor sources in Indian country.

* * * * *

(c) * * *

(1) * * *

(ii) If your true minor source is not an oil and natural gas source, as defined in § 49.102, and you commence construction after August 30, 2011, and before September 2, 2014, you must register your source with the Reviewing Authority within 90 days after the source begins operation. If your new true minor source or minor modification of an existing true minor source is an oil and natural gas source, as defined in § 49.102, and you commence construction after August 30, 2011, and before October 3, 2016, you must register your source with the Reviewing Authority within 90 days after the source begins operation.

(iii) If your true minor source is not an oil and natural gas source, as defined in § 49.102, and you commence construction or modification of your source on or after September 2, 2014, and your source is subject to this rule, you must report your source's actual emissions (if available) as part of your permit application and your permit application information will be used to fulfill the registration requirements described in § 49.160(c)(2). If your true minor source is an oil and natural gas source, as defined in § 49.102, and you commence construction or modification of your source on or after October 3, 2016, you must report your source's actual emissions (if available) as part of your permit application or registration of oil and natural gas production sources using a form provided by the EPA, ''Registration for New True Minor Oil and Natural Gas Sources and Minor Modifications at Existing True Minor Oil and Natural Gas Sources'' (available at: *http://www.epa.gov/air/tribal/tribalnsr.html* or from EPA Regional Offices), and your permit application or registration for oil and natural gas production sources will be used to fulfill the registration requirements described in § 49.160(c)(2).

(iv) Minor sources complying with §§ 49.101 to 49.105 for oil and natural gas production, as defined in § 49.102, must submit a registration form 30 days prior to beginning construction that contains the information in § 49.160(c)(2). The form titled ''Registration for New True Minor Oil and Natural Gas Sources and Minor Modifications at Existing True Minor Oil and Natural Gas Sources'' is available at: *http://www.epa.gov/air/tribal/tribalnsr.html* or from EPA Regional Offices. This form is submitted instead of the application form required in § 49.160(c)(1)(iii).

* * * * *

(4) *Duty to obtain a permit or comply with the Federal Implementation Plan for oil and natural gas production sources.* Submitting a registration form does not relieve you of the requirement to obtain any required permit, including a preconstruction permit, or to comply with the Federal Implementation Plan for oil and natural gas production if your source or any physical or operational change at your source would be subject to any minor or major NSR rule.

* * * * *

■ 7. Section 49.167 is amended by revising the introductory text of paragraph (d) and adding paragraph (d)(4) to read as follows:

§ 49.167 Definitions.

* * * * *

(d) *Indian country,* as defined in 18 U.S.C. 1151, means the following as applied to this program:

* * * * *

(4) For purposes of this rule, references to Indian country include all Indian reservation lands where no EPA-approved program is in place and all other areas of Indian country where no EPA-approved program is in place and over which an Indian tribe, or the EPA, has demonstrated that a tribe has jurisdiction.

* * * * *

[FR Doc. 2015–21025 Filed 9–17–15; 8:45 am]

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ENVIRONMENTAL PROTECTION AGENCY

[EPA–HQ–OAR–2015–0216; FRL–9932–42–OAR]

RIN 2060–ZA22

Release of Draft Control Techniques Guidelines for the Oil and Natural Gas Industry

AGENCY: Environmental Protection Agency (EPA).

ACTION: Notice of availability.

SUMMARY: The Environmental Protection Agency (EPA) is announcing the availability of a draft Control Techniques Guidelines (CTG) document for select oil and natural gas industry emission sources. This document, when finalized, will provide state, local, and tribal air agencies (air agencies) information to assist them in determining reasonably available control technology (RACT) for volatile organic compound (VOC) emissions from such sources.

DATES: Comments must be received on or before November 17, 2015.

ADDRESSES: The draft *Control Techniques Guidelines for the Oil and Natural Gas Industry* is available primarily via the Internet at *http://www.epa.gov/airquality/oilandgas/index.html.*

Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2015–0216, to the *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (*i.e.* on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions. Direct your comments to Docket ID No. EPA–HQ–OAR–2015–0216. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *http://www.regulations.gov,* including any personal information provided, unless the comment includes information claimed to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Do not submit information that you consider to be CBI or otherwise protected through *http://www.regulations.gov* or email. The *http://www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you send an email comment directly to the EPA without going through *http://www.regulations.gov,* your email address will be automatically captured and included as part of the comment that is placed in the public docket and made available on the Internet. If you submit an electronic comment, the EPA recommends that you include your name and other contact information in the body of your comment and with any CD you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. Electronic files should avoid the use of special characters, avoid any form of encryption and be free of any defects or viruses. For additional information about the EPA's public docket, visit the EPA Docket Center homepage at *http://www.epa.gov/epahome/dockets.htm.* For additional instructions on submitting comments, go to section I.A of the **SUPPLEMENTARY INFORMATION** section of this document.

Docket. All documents in the docket are listed in the *http://www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, will be publicly available only in hard copy. Publicly available docket materials are available either electronically at *http://www.regulations.gov* or in hard copy at the U.S. Environmental Protection Agency, EPA Docket Center, EPA WJC West Building, Room 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: Ms. Charlene Spells, U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, Sector Policies and Programs Division (E143–05), Research Triangle Park, NC 27711; telephone number:(919) 541- 5255; fax number:(919) 541–3470; email:*spells.charlene@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. What should I consider as I prepare my comments?

Submitting CBI. Do not submit this information to the EPA through *http://www.regulations.gov* or email. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a CD that you mail to the EPA, mark the outside of the CD as CBI and then identify electronically within the CD the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2. Send or deliver information identified as CBI only to the following address: Tiffany Purifoy, OAQPS Document Control Officer (C404–02), U.S. EPA, Research Triangle Park, NC 27711, Attention Docket ID No. EPA–HQ–OAR–2015–0216.

II. Information About the Document

Section 172(c)(1) of the Clean Air Act (CAA) provides that State Implementation Plans (SIPs) for nonattainment areas must include ''reasonably available control measures'', including ''reasonably available control technology'' (RACT), for existing sources of emissions. Section 182(b)(2)(A)of the CAA requires that for Moderate ozone nonattainment areas, states must revise their SIPs to include RACT for each category of VOC sources covered by a CTG document issued between November 15, 1990, and the date of attainment. CAA section 182(c) through (e) applies this requirement to States with ozone nonattainment areas classified as Serious, Severe and Extreme.

The CAA also imposes the same requirement on States in ozone transport regions (OTR). Specifically, CAA Section 184(b) provides that states in the Ozone Transport Region (OTR) must revise their SIPs to implement RACT with respect to all sources of VOCs in the state covered by a CTG issued before or after November 15, 1990. CAA section 184(a) establishes a single OTR comprised of Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont and the Consolidated Metropolitan Statistical Area (CMSA) that includes the District of Columbia.

The EPA defines RACT as ''the lowest emission limitation that a particular source is capable of meeting by the application of control technology that is reasonably available considering technological and economic feasibility'' (44 FR 53761, September 17, 1979). The EPA is developing this CTG to provide air agencies information to assist them in determining RACT for VOC from select oil and natural gas emission sources. In developing the CTG, the EPA, among other things, evaluated the sources of VOC emissions from the oil and natural gas industry and the available control approaches for addressing these emissions, including the costs of such approaches. Based on available information and data, the EPA is providing draft recommendations for RACT for select oil and natural gas industry emission sources. The VOC RACT recommendations contained in this draft CTG were made based on a review of the 1983 CTG, the oil and natural gas NSPS, existing state and local VOC emission reduction approaches, and information on costs, emissions and available emission control technologies obtained since issuance of these guidelines and rules. For instance, the EPA released for external peer review five technical white papers on potentially significant sources of emissions in the oil and gas sector. We considered information included in the white papers, along with the input we received from the peer reviewers and the public, when evaluating and recommending a RACT level of control for emission sources. Upon finalization of the CTG, air agencies can use the recommendations in the CTG to inform their determinations as to what constitutes RACT for VOC for these oil and natural gas industry emission sources in their particular areas. The information contained in the CTG is provided only as guidance. This guidance does not change, or substitute for, requirements specified in applicable sections of the CAA or the EPA's regulations; nor is it a regulation itself. The CTG does not impose any legally binding requirements on any entity. It provides only recommendations for air agencies to consider in determining RACT. Air agencies are free to implement other technically-sound approaches that are consistent with the CAA and the EPA's regulations.

The recommendations contained in the CTG are based on data and information currently available to the EPA. These general recommendations may not apply in all situations. Regardless of whether a state chooses to implement the recommendations contained in a CTG through state rules, or to issue state rules that adopt different approaches for RACT for VOC from oil and natural gas industry emission sources, states must submit their RACT rules to the EPA for review and approval as part of the SIP process. The EPA will evaluate the rules and determine, through notice and comment rulemaking in the SIP review process, whether the submitted rules meet the RACT requirements of the CAA and the EPA's regulations. To the extent a state adopts any of the recommendations in this CTG, upon its finalization, into its state RACT rules, interested parties can raise questions and objections about the substance of this guidance and the appropriateness of the application of this guidance to a particular situation during the development of the state rules and the EPA's SIP review process.

Section 182(b)(2) of the CAA requires that a CTG issued between November 15, 1990, and the date of attainment provide the period for submitting SIP revisions in response to such CTG. In the draft CTG, the EPA is providing a two-year period, from the date of final issuance, for the required submittal.

The Tribal Authority Rule (63 FR 7254, February 12, 1998) (TAR) identifies CAA provisions for which it is appropriate to treat Indian tribes in the same manner as states (TAS). Pursuant to the TAR, tribes may apply for TAS for purposes of CAA section 110 and Part D planning requirements in CAA section 172. As a result, tribes may, but are not required to, apply for TAS for the purpose a developing a tribal implementation plan (TIP) addressing RACT for sources located in a Moderate (or higher) nonattainment area for ozone within the tribe's jurisdiction. If the EPA grants that status and approves the TIP, the tribe would implement RACT in Moderate (or higher) ozone nonattainment areas within the geographic scope of the TAS designation. If a tribe does not seek and obtain the authority from the EPA to establish a plan, the EPA will be responsible for establishing CAA section 110 and 172 plans for reservations and trust lands if the EPA determines that such a plan is necessary or appropriate to protect air quality in such areas.

III. Specific Comments Solicited

In addition to providing an opportunity to review and comment on the draft CTG, the EPA is also soliciting specific comment on the following:

1. Information on costs associated with retrofitting an existing storage vessel to allow routing of emissions to a control device.
2. Information on the implementation of a monitoring plan that includes the use of optical gas imaging for fugitive emissions at existing well sites.
3. Interaction of the CTG with new builds in areas affected by the CTG. Refer to materials in the docket (EPA–HQ–OAR–2015–0216).
4. The appropriateness of a daily average of 15 barrel equivalents as a representative threshold to define low production wells for purposes of requiring a fugitive emissions program and information on fugitive air emissions associated with low production wells.

Dated: August 18, 2015.

Gina McCarthy,

Administrator.

[FR Doc. 2015–21027 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Parts 49, 51, 52, et al.

[EPA–HQ–OAR–2013–0685; FRL–9931–97–OAR]

RIN 2060–AS06

Source Determination for Certain Emission Units in the Oil and Natural Gas Sector

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: The U.S. Environmental Protection Agency (EPA) is proposing to clarify the term ''adjacent'' in the definitions of: ''building, structure, facility or installation'' used to determine the ''stationary source'' for purposes of the Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) programs and ''major source'' in the title V program as applied to the oil and natural gas sector. The EPA has previously issued guidance on how to assess ''adjacency'' for this industry, but the use of the guidance has been challenged, resulting in uncertainty for the regulated community and for permitting authorities. The EPA is proposing to clarify how properties in the oil and natural gas sector are determined to be adjacent in order to assist permitting authorities and permit applicants in making consistent source determinations for this sector. In this action, the EPA is proposing two options for determining whether two or more properties in the oil and natural gas sector are ''adjacent'' for purposes of defining the ''stationary source'' in the PSD and NNSR programs, and ''major source'' for the title V program (referred to collectively as ''source''). The preferred option would define ''adjacent'' for the oil and natural gas sector in terms of proximity. The EPA is co-proposing and taking comment on an alternative option to define ''adjacent'' in terms of proximity or functional interrelatedness.

DATES: *Comments.* Comments must be received on or before November 17, 2015.

Public Hearing. The EPA will hold public hearings on the proposal. Details will be announced in a separate document.

ADDRESSES: *Comments.* Submit your comments, identified by Docket ID No. EPA–HQ–OAR–2013–0685, to the *Federal eRulemaking Portal: http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. If you need to include CBI as part of your comment, please visit *http://www.epa.gov/dockets/comments.html* for instructions. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. For additional submission methods, the full EPA public comment policy, and general guidance on making effective comments, please visit *http://www.epa.gov/dockets/comments.html.* For additional instructions on submitting comments, go to the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: For further general information on this rulemaking, contact Ms. Cheryl Vetter, Office of Air Quality Planning and Standards (C504–03), U.S. Environmental Protection Agency, by phone at (919) 541-4391, or by email at *vetter.cheryl@epa.gov.*

SUPPLEMENTARY INFORMATION:

I. General Information

A. Does this proposal apply to me?

Entities potentially affected directly by this proposal include owners and operators of sources of new and modified oil and gas sector operations. Such entities are expected to be in the groups indicated below. In addition, state, local and tribal governments may be affected by the rule if they update state rules to adopt these changes.

Industry group	NAICS Code[1]
Oil and Gas Extraction	21111.
Crude Petroleum and Natural Gas Extraction	211111.
Natural Gas Liquid Extraction	211112.
Drilling Oil and Gas Wells	213111.
Support Activities for Oil and Gas	213112.
Natural Gas Distribution	221210.
Pipeline Distribution of Crude Oil	486110.
Pipeline Distribution of Natural Gas	486210.
Federal Government	May Be Affected.
State/Local/Tribal Government	May Be Affected.

B. What should I consider as I prepare my comments for the EPA?

When submitting comments, remember to:

• Identify the rulemaking by docket number and other identifying information (subject heading, **Federal Register** date and page number).

• Follow directions—The agency may ask you to respond to specific questions or organize comments by referencing a Code of Federal Regulations (CFR) part or section number.

• Explain why you agree or disagree; suggest alternatives and substitute language for your requested changes.

• Describe any assumptions and provide any technical information and/or data that you used.

• If you estimate potential costs or burdens, explain how you arrived at your estimate in sufficient detail to allow for it to be reproduced.

• Provide specific examples to illustrate your concerns, and suggest alternatives.

• Explain your views as clearly as possible, avoiding the use of profanity or personal threats.

• Make sure to submit your comments by the comment period deadline identified.

[1] North American Industry Classification System (NAICS).

C. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this action will be posted at *http://www.epa.gov/airquality/oilandgas/actions.html.*

D. How is this document organized?

The information presented in this document is organized as follows:

I. General Information
A. Does this proposal apply to me?
B. What should I consider as I prepare my comments for the EPA?
C. Where can I get a copy of this document and other related information?
D. How is this document organized?
II. Statutory, Regulatory and Policy Background for Proposal
A. Statutory and Regulatory Background
B. How has the EPA applied the statutory and regulatory definitions?
C. Oil and Natural Gas Sector
D. What are the air emissions resulting from the oil and natural gas sector?
E. How does the EPA regulate air emissions from the oil and natural gas sector?
F. How has the EPA defined the source for the oil and natural gas sector previously?
G. What approaches has the EPA taken recently regarding implementation of NSR and title V permitting for oil and natural gas sector sources?
H. What is the purpose of this proposed action?
I. Policy Discussion
J. Why is the EPA proposing this action at this time?
K. What is the effect of this proposed rulemaking on other industries?
L. What is the effect of this proposed rulemaking on permitting authorities?
III. What are the options that the EPA is considering?
A. Define Source Based on Proximity (Similar to the NESHAP)
B. Define Source To Include Exclusively Functionally Interrelated Equipment
C. Impacts of the Options on Air Permitting
D. Proposal is Limited to Onshore Oil and Gas Operations
IV. Environmental Justice Considerations
V. Statutory and Executive Order Reviews
A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act
C. Regulatory Flexibility Act
D. Unfunded Mandates Reform Act
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use
I. National Technology Transfer and Advancement Act
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Determination Under Section 307(d) Statutory Authority

II. Statutory, Regulatory and Policy Background for Proposal

A. Statutory and Regulatory Background

The major New Source Review (NSR) programs found in parts C and D of Title I of the Clean Air Act (CAA or Act) are preconstruction review and permitting programs that apply to new and modified major stationary sources of air pollutants subject to regulation under the Act. In areas where air quality does not meet the primary or secondary National Ambient Air Quality Standards (NAAQS) for a given pollutant and in the ozone transport region (OTR), which includes states in the Northeast and Mid-Atlantic regions, the program is implemented under part D of title I of the Act. This is called the ''nonattainment'' NSR (NNSR) program. In areas that meet the NAAQS, or ''attainment'' areas, or where we [2] cannot determine whether those standards are met, or ''unclassifiable'' areas, the requirements under part C of title I of the Act apply. This program is called the PSD program. The regulations for these two NSR programs are found in 40 CFR 51.165, 51.166, 52.21, 52.24 and part 51, appendix S.

The NSR permitting programs are primarily implemented by state and local permitting authorities either through programs in their approved State Implementation Plans (SIPs) or through delegation of the federal program by the EPA. The EPA implements the federal PSD program and the NNSR program directly in reservation areas of Indian country and non-reservation areas of Indian country over which a tribe or the EPA has demonstrated that a tribe has jurisdiction, unless a tribe has developed a Tribal Implementation Plan (TIP). The EPA may also implement the federal PSD program directly in areas where the state or local area has not developed a SIP-approved program or has not requested delegation of the program by the EPA. States are also required to have legally enforceable procedures that will allow them to prevent the construction or modification of a source that will interfere with attainment or maintenance of a NAAQS. In addition to the major source permitting programs, this is typically accomplished through a state or local ''minor'' new source permitting program. The EPA implements a minor source permitting program in all reservation areas of Indian country, unless a tribe has developed a TIP and in any non-reservation areas of Indian country for which a tribe, or the EPA acting in the tribe's place, has demonstrated that the tribe has jurisdiction.

The NSR program applies to new and modified stationary sources of emissions. The CAA generally defines the term ''stationary source'' as ''any source of an air pollutant'' except those emissions from certain mobile sources or engines under CAA section 216 [CAA section 302(z)]. The Act also defines some other terms that form the basis of specific NSR programs. So, for example, the PSD program requires a preconstruction permit for any ''major emitting facility'' constructed after a particular date [CAA section 164(a)], and defines a ''major emitting facility'' as a ''stationary source'' emitting or with the potential to emit more than a certain amount of air pollutants [CAA section 169(1)].

Adhering to the statutory language in CAA section 111(a)(3), we have defined the term ''stationary source'' to mean ''any building, structure, facility, or installation which emits or may emit a regulated NSR pollutant'' [40 CFR 52.21(b)(5); 40 CFR 51.165(a)(1)(i); 40 CFR 51.166(b)(5)]. We have then further defined the four statutory terms ''building, structure, facility, or installation'' collectively in our NSR regulations to mean ''all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control),'' where the ''same industrial grouping'' refers to the two-digit Standard Industrial Classification code [40 CFR 52.21(b)(6); 40 CFR 51.165(a)(1)(ii); 40 CFR 51.166(b)(6)].[3] These three regulatory factors: (1) Same industrial grouping; (2) location on contiguous or adjacent properties; and (3) under the control of the same person or persons must be evaluated on a case-by-case basis for each permitting decision.

In addition to the pre-construction permitting requirements of the NSR

[2] In this preamble, the term ''we'' and ''our'' refers to the EPA.

[3] The four-digit SIC code was the only code system in use at the time our rules were developed. This classification system has since been replaced by the six-digit NAICS, which was developed with Canada and Mexico, and is used for classifying North American businesses. While the SIC codes are no longer updated, the United States Department of Labor's Occupational Safety and Health Administration still maintains the list of SIC codes for reference.

program, title V of the CAA also requires a ''major source'' to obtain an operating permit, known as a title V permit [CAA section 501(2); CAA 502]. The title V definition of major source refers to the definitions in other sections of the Act, including the definition of major source for hazardous air pollutants (CAA section 112), the general CAA definition of major stationary source (CAA section 302) and the definition of major stationary source under the NNSR program. Each of these programs set different numerical emissions thresholds at which permitting requirements apply, which then become the basis for the major source determination in the title V program.

Our operating permit regulations define major source as ''any stationary source (or group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping . . .'' (40 CFR 70.2, 71.2). As in the NSR programs, we have defined industrial grouping to refer to the two-digit SIC code (40 CFR 70.2, 71.2). Many state and local permitting authorities have approved title V permitting programs that have adopted similar definitions.

B. How has the EPA applied the statutory and regulatory definitions?

Source owner/operators and permitting authorities assess the three regulatory factors—same industrial grouping, location on contiguous or adjacent property, and under common control—on a case-by-case basis to determine which pollutant-emitting activities should be included as part of a single source when determining applicability of the NSR and title V permitting requirements. In the original promulgation and later application of these three factors, we have been mindful of the direction the D.C. Circuit Court of Appeals provided that the ''source'' for permitting purposes should comport with the ''common sense notion of a plant'' (45 FR 52694, August 7, 1980 citing *Alabama Power* v. *Costle).* In the *Alabama Power* decision, the Court said that EPA cannot treat contiguous and commonly owned units as a single source unless they ''fit within the four statutory terms . . .'' (*i.e.,* the terms building, structure, facility and installation). The Court said that we should ''. . . provide for the aggregation, where appropriate, of industrial activities according to considerations such as proximity and ownership.'' *Alabama Power Co.* v. *Costle,* 636 F. 2d 323, 397 (D.C. Cir. 1979). Examples of the case-by-case determinations made by the EPA, or by permitting authorities with the EPA's input, applying these principles over several decades of NSR permitting are available at *http://www.epa.gov/region07/air/nsr/nsrindex.htm.*

The EPA later promulgated the title V major source definition found at 40 CFR 70.2 (57 FR 32250, July 21, 1992) and 71.2 (61 FR 34202, 34210, July 1, 1996). Not only were these definitions consistent with each other, but EPA was also clear that the language and application of the title V definition was to be consistent with the language and application of the PSD definition contained in section 52.21 (61 FR 34210, July 1, 1996). Examples of case-by-case source determinations made by the EPA, or by permitting authorities with the EPA's input, that apply the title V definitions are available at *http://www.epa.gov/region7/air/title5/t5index.htm.*

Reviewing both the NSR and title V guidance regarding source determinations, it is clear that we have used the term ''contiguous or adjacent'' to mean that the land associated with the source (*i.e.,* building, structure, facility or installation) is connected to (*i.e.,* contiguous) or nearby (*i.e.,* adjacent) another source. In response to the *Alabama Power* decision, the EPA promulgated the 1980 PSD rule, including the definitions used to determine the scope of the source for permitting purposes (45 FR 52676, August 7, 1980). We explained that the 3-part test (same industrial grouping, location on contiguous or adjacent property, and under common control) would comply with the court decision by reasonably comporting with the purposes of the PSD program, approximating the common sense notion of a plant, and avoiding aggregating pollutant-emitting activities that would not fit within the ordinary meaning of building, structure, facility or installation (45 FR at 52694, August 7, 1980). In so doing, we considered but chose not to add a fourth factor or ''functional interrelationship'' test to the criteria for defining a source, as at that time, we believed that such a test would ''embroil[] the Agency in numerous fine-grained analyses'' (45 FR 52695, August 7, 1980). In the same rulemaking, we said that we did not intend ''source'' to include activities that are many miles apart along something like a pipeline or transmission line as a single source, but also noted that we were ''unable to say precisely at this point how far apart activities must be in order to be treated separately'' (45 FR 52695, August 7, 1980).

Even though our regulations use the term ''adjacent,'' they do not define ''adjacent.'' Similarly, even though the EPA's historic interpretation is that ''adjacent'' means ''nearby,'' neither our regulations nor our historic interpretations set a specific distance that we would consider ''nearby.'' Over the years, the EPA has considered both the distance between two or more sources and whether they share an operational dependence or functional interrelatedness to determine whether they are ''adjacent.'' Even though our regulations do not explicitly define ''adjacent,'' we have provided policy interpretations of ''adjacency'' over time in the context of individual permitting actions many times because we were asked by permitting authorities to advise them on how to define a source within a specific permitting action. As is the case for most permitting-related decisions, these determinations were made on a case-by-case basis, considering the specific facts in each instance. In many of these cases and as explained in the examples below, we cited the principle of the ''common sense notion of a plant'' in making a determination regarding the scope of the source.

In one example, we determined that two aluminum smelting operations within the same SIC code (3334), located approximately 3.4 miles apart and commonly owned by Alcoa, should be considered a single source for purposes of NSR applicability. Alcoa requested confirmation of this single source determination after it purchased one of the plants from another company, allowing both operations to share common control and management as well as a single SIC code. The EPA determined that the two operations should be considered adjacent because of the shared materials and personnel and the company's assertion that the two plants would be operated as one facility.[4]

In one case specific to the oil and natural gas sector, the EPA determined, in a letter issued by EPA Region 5 to Summit Petroleum Corporation, that an oil and gas sweetening plant and approximately 100 oil and gas wells located within the boundaries of the Saginaw Chippewa Band's Isabella Reservation in Michigan were a single

[4] Riva, Steven C. ''Alcoa Messena Modernization Project and Request for a Single Source Determination.'' March 9, 2009. EPA Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/alcoany.pdf* and in the docket for this rulemaking.

major source for purposes of the title V operating permit program.[5] The EPA based its decision on its evaluation that the sweetening plant and wells share the same two-digit SIC code and are under common control (Summit Corporation). In addition, the EPA concluded that the plant and the wells were adjacent and, thus, a single source given their proximity and exclusive interdependence as demonstrated by the following facts: All of the wells are located within an 8-mile radius of the sweetening plant; all are connected by a dedicated system of pipes; and all oil and gas from the wells must be processed through the sweetening plant before it can be marketed. That determination was later challenged and overturned, as will be discussed later in this notice.

Finally, in another example involving the oil and natural gas sector, the EPA determined that two natural gas compressor stations (Florida River and Wolf Point) and the numerous well sites owned or operated by BP and located within the Northern San Juan Basin should not be considered a single stationary source. In that situation, unlike the Summit Petroleum case discussed previously, there was no dedicated interrelationship between the wells and the compressor stations that would indicate that they should be treated as a single ''plant.'' Gas from the individual wells could flow to the two BP compressor stations, or other compressor stations. Gas production from BP's wells would not have to stop if one or both of the BP compressor stations were shut down. Additionally, the gathering pipeline between the wells and the stations co-mingled gas from operators other than BP and the compressor stations likewise accepted gas from other operators. The EPA's determination that this complex, dynamic system did not resemble a ''common sense notion of a plant'' was also challenged, and was settled.[6]

In each of these examples, the EPA based its opinion on an analysis of the specific facts in the individual case. We have not established a ''bright-line'' distance beyond which we would always consider operations to be separate sources. Neither have we established a distance within which we would always consider operations to be one source. We have also not established that certain operations must always (or never) be considered together for permitting purposes.

C. Oil and Natural Gas Sector

The United States Census Bureau's North American Industry Classification System (NAICS) describes the Oil and Gas Extraction industry (NAICS Code 2111) as including activities such as ''exploration for crude petroleum and natural gas; drilling, completing, and equipping wells; operation of separators, emulsion breakers, de-silting equipment, and field gathering lines for crude petroleum and natural gas; and all other activities in the preparation of oil and gas up to the point of shipment from the producing property.''[7] This definition includes activities such as natural gas processing and liquids extraction, and sulfur recovery from natural gas. Pipeline transmission and distribution of oil and natural gas, and storage of natural gas are included in NAICS subsector 486 Pipeline Transportation.

The EPA has previously described in the preamble to its proposed New Source Performance Standard (NSPS) for the oil and natural gas sector that this sector includes operations in the extraction and production of oil and natural gas, and the processing, transmission and distribution of natural gas. For oil, we described the sector as including ''all operations from the well to the point of custody transfer at a petroleum refinery.'' For natural gas, we described it as including all operations from the well to the customer (76 FR 52738, 52744, August 20, 2011).

For purposes of this proposed action, we are primarily interested in the first two of these: Oil and natural gas production, and natural gas processing, or what may be referred to in the industry as ''upstream'' and ''midstream'' operations. For reasons that will be explained later in this notice, we do not intend to apply the proposed clarification to operations that take place offshore. Onshore production operations include ''the wells and all related processes used in the extraction, production, recovery, lifting, stabilization, separation, or treating of oil and/or natural gas (including condensate). Production components may include, but are not limited to, wells and related casing head, tubing head and ''Christmas tree'' piping, as well as pumps, compressors, heater treaters, separators, storage vessels, pneumatic devices and dehydrators. Production operations also include the well drilling, completion and workover processes, and include all the portable non-self-propelled apparatus associated with those operations. Production sites include not only the ''pads'' where the wells are located, but also include standalone sites where oil, condensate, produced water and gas from several wells may be separated, stored and treated. The production sector also includes the low pressure, small diameter, gathering pipelines and related components that collect and transport the oil, gas and other materials and wastes from the wells to the refineries or natural gas processing plants (76 FR 52744, August 20, 2011).

Natural gas processing operations are aimed at removing impurities and other by-products from the extracted gas. Natural gas consists primarily of methane. It may also contain water vapor, hydrogen sulfide (H_2S), carbon dioxide (CO_2), helium, nitrogen and other compounds. It commonly exists in mixtures with other hydrocarbons, referred to as natural gas liquids (NGL). Natural gas must be processed to remove these other compounds and gases before the gas is considered pipeline quality suitable for transmission and distribution. Natural gas processing removes and recovers the liquids, and non-methane gases, all or some of which may be sold.

D. What are the air emissions resulting from the oil and natural gas sector?

Emissions from the oil and natural gas sector include volatile organic compounds (VOC), greenhouse gases (including methane), H_2S, sulfur dioxide (SO_2), carbon monoxide (CO) and nitrogen oxides (NO_X). VOCs, including some hazardous air pollutants (HAP), are generally emitted during well completions, from equipment leaks and from storage tanks. Emissions of the greenhouse gas methane may also come from these sources while emissions of the greenhouse gas CO_2 come primarily from combustion sources, such as flares, engines and compressors. Emissions of

[5] Newton, Cheryl. ''Summit Petroleum Corporation Single Source Determination.'' October 18, 2010. EPA Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/singler5.pdf* and in the docket for this rulemaking.

[6] Videtich, Callie. ''BP American Production Company's Florida River Compression Facility Single Source Determination.'' October 18, 2010. EPA Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/singler8.pdf* and in the docket for this rulemaking. The Environmental Appeals Board (EAB) docket for CAA Appeal No. 10–04 is available at *http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/77355bee1a56a5aa8525711400542d23/2c6cf712eac2d7b38525788b00545227!OpenDocument&Highlight=2,CAA,10-04.* The petition for review by the EAB, EPA Region 8's response, and the reply by petitioner are available in the docket for this rulemaking.

[7] U.S. Department of Commerce, United States Census Bureau, North American Industry Classification System, 2012 NAICS Definition, Sector 21—Mining, Quarrying, and Oil and Gas Extraction, 21111 Oil and Gas Extraction *http://www.census.gov/cgi-bin/sssd/naics/naicsrch?code=21111&search=2012* accessed 12/03/2013.

NO_X and CO are also a result of these combustion operations. Emissions of sulfur compounds come from production and processing operations that treat ''sour gas,'' that is, natural gas with an H_2S content of greater than 0.25 gr/100 scf.

E. How does the EPA regulate air emissions from the oil and natural gas sector?

In addition to the source-specific permitting required by the NSR and title V programs, air emissions from the oil and natural gas sector are also regulated through other CAA-based rules. The EPA first listed crude oil and natural gas production for NSPS development in 1979 (44 FR 49222, August 21, 1979). An NSPS, 40 CFR part 60, subpart KKK, was promulgated in 1985 that addressed VOC emissions from leaking components at onshore natural gas processing facilities (50 FR 26122, June 24, 1985). A second NSPS, regulating SO_2 emissions from natural gas processing plants, 40 CFR part 60, subpart LLL, was promulgated in 1985 (50 FR 40158, October 1, 1985). In 2012, the EPA finalized revisions to these NSPS and established standards in 40 CFR part 60, subpart OOOO, limiting VOC emissions from gas wells, centrifugal compressors, reciprocating compressors, pneumatic controllers and storage vessels (77 FR 49490, August 16, 2012). In 2013 and 2014, the EPA made certain amendments to the 2012 NSPS standards in order to improve implementation of the standards (78 FR 58416, September 23, 2013 and 79 FR 79018, December 31, 2014). Separately, the EPA is proposing to expand the NSPS (subpart OOOO) to regulate several additional categories of emitting equipment in this sector.

The EPA has also regulated emissions of HAP from certain oil and natural gas sector processes through use of National Emissions Standards for Hazardous Air Pollutants (NESHAP), specifically the Oil and Natural Gas Production NESHAP (40 CFR part 63, subpart HH) and Natural Gas Transmission and Storage NESHAP (40 CFR part 63, subpart HHH). These regulations were first promulgated in 1999 (64 FR 32610, June 17, 1999) and were amended in 2012 (77 FR 49490, August 16, 2012).

F. How has the EPA defined the source for the oil and natural gas sector previously?

As discussed in the previous section, selected equipment and emitting activities involved in oil and gas production are regulated under both the NSPS and NESHAP programs. The NSPS and NESHAP focus on technology-based standards for industrial source categories, and do not approach the regulation of stationary sources in the same way as required for NSR permitting.

The definition of a major source in the NESHAP program is similar to, but distinguishable from, the definition of stationary source used in the NSR permitting programs. The NESHAP program defines a major source as a stationary source or a group of stationary sources ''within a contiguous area'' (40 CFR 63.2). This ''major source'' definition differs from the definition of stationary source used in the NSR permitting programs because it does not include ''adjacent properties'' [*e.g.,* 40 CFR 52.21(b)(5)]. A major source under CAA section 112 is further defined as any stationary source or group of stationary sources ''that emits or has the potential to emit considering controls, in the aggregate 10 tons per year (tpy) or more of any HAP or 25 tpy or more of any combination of HAP.'' [CAA section 112(a)(1)]. An area source of HAP is one that is not a major source of HAP.

When Congress revised CAA section 112 in 1990, however, it included a specific provision discussing how oil and gas wells and pipeline facilities were to be treated with respect to regulating emissions of HAP [CAA section 112(n)(4)(A)]. This section provides that ''notwithstanding'' the definitions of major source in section 112, the emissions from any oil or gas exploration or production well (with its associated equipment) and emissions from any pipeline compressor or pump station ''shall not be aggregated with emissions from other similar units'' to determine whether the units or stations are major sources. Congress specified this whether the units are in a contiguous area or under common control. In the case of any oil or gas exploration or production well (with its associated equipment), such emissions ''shall not be aggregated for any purpose under this section.''

In the NESHAP for Oil and Natural Gas Production Facilities, the EPA defines the affected source consistent with this requirement of the Act, including which associated equipment should be part of the facility, which associated equipment could potentially be aggregated, and which cannot be aggregated as per CAA section 112(n)(4)(A) [40 CFR 63.760(b)]. The EPA defines this associated equipment to include ''equipment associated with an oil or natural gas exploration or production well, and includes all equipment from the wellbore to the point of custody transfer'' (40 CFR 63.761). The EPA defines the facility for purposes of the NESHAP to mean ''the grouping of equipment where hydrocarbon liquids are processed, upgraded (*i.e.,* remove impurities or other constituents to meet contract specifications), or stored prior to the point of custody transfer'' or where natural gas is ''processed, upgraded, or stored'' prior to natural gas transmission and storage. For the purpose of the NESHAP major source determination, facility (including a building, structure, or installation) means oil and natural gas production and processing equipment that is located within the boundaries of an individual surface site as defined in the NESHAP (40 CFR 63.761).

Furthermore, the EPA defines surface site as ''any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed'' (40 CFR 63.761). The effect of these definitions is to define the affected facility based on the emissions from equipment and activities that are in close proximity to each other. The EPA stated that its intent in defining affected facility in this way was both to comply with the specific language in CAA section 112(n)(4), and to reduce the burden on owners and operators in making source determinations. The EPA stated at that time its belief that it was not reasonable to aggregate emissions from surface sites that are located on the same lease, but are at great distances from each other, even though they would be under common control (64 FR 32618, June 17, 1999).

G. What approaches has the EPA taken recently regarding implementation of NSR and title V permitting for oil and natural gas sector sources?

As was the case with other industry categories, the EPA initially approached permitting decisions in the oil and natural gas sector on a case-by-case basis without any specific guidance until 2007. At that time, because of an increase in oil and gas development, and an increase in permit activity, the EPA issued the first guidance document specific to this industry. The EPA built on the idea of using the surface site, as defined in 40 CFR 63.761, and the proximity of surface sites to each other in permitting guidance, when it issued a guidance document titled ''Source Determinations for Oil and Gas Industries'' in 2007.[8] This 2007 memo is

[8] Wehrum, William. ''Source Determinations for Oil and Gas Industries.'' January 12, 2007. EPA Continued

relevant to our proposed action because it acknowledged that source determinations within the oil and gas industry may not be as straightforward as those within other regulated industries. We note that even in cases that clearly meet the tests of same SIC code and common control, the nature of oil and gas exploration and production operations may require a detailed evaluation to determine whether sources are on contiguous or adjacent properties. Production fields, even if under the control of a single operator, may cover large areas. Unlike many other industries, however, the expanse of land on which these commonly-controlled operations are located is frequently not owned or controlled by the owner/operator of the oil and gas activity. Instead, the producers may control only the surface area that holds the well and associated production equipment.

As discussed earlier in this notice, EPA has previously said that it would not consider all facilities along a pipeline to be one source. The 2007 memo built upon that idea to conclude that, for the oil and gas production industry, ''we do not believe determining whether two activities are operationally dependent drives the determination as to whether two properties are contiguous or adjacent, because it would embroil the Agency in precisely the fine-grained analysis we intended to avoid and would potentially lead to results which do not adhere to the common sense notion of a plant.'' Thus, the 2007 memo acknowledged that permitting authorities may consider proximity, and not operational dependence, as the most informative factor in determining the scope of a source, and recommended the approach used in CAA section 112 and the NESHAP for Oil and Natural Gas Production Facilities (the ''surface site'') as the starting point for determining the boundaries of the source for NSR and title V. Beyond the surface site, the memo recommends that permitting authorities consider aggregating multiple surface sites if they are in close proximity, *i.e.,* physically adjacent or separated by no more than a short distance. However, consistent with the EPA's overall permitting practice, the 2007 memo concluded that the decision of whether a permitting authority should aggregate two or more pollutant-emitting activities into a single source for permitting remains a case-by-case decision taking into consideration the factors relevant to the specific case.

In 2009, the EPA withdrew the 2007 memo.[9] In doing so, we reinstated the use of the fundamental criteria for making source determinations for the oil and natural gas sector based on the use of the three factors contained in our regulations; same SIC code, common control, and location on contiguous or adjacent property. This fact-specific examination is consistent with the EPA's historical practice in other industries, and is in contrast to the simplified approach of relying principally on proximity that was the focus of the 2007 memorandum. From 2009 forward, the EPA recommended that permitting authorities conduct each source determination based on a case-by-case evaluation of the emissions activities at each building, structure, facility or installation. The 2009 memo acknowledged that proximity might well serve as the overwhelming factor in a permitting authority's source determination decision, but the conclusion could only be justified after examining all relevant factors, consistent with regulatory requirements and historical practice.

The EPA has had direct experience as the permitting authority in making source determinations for onshore oil and gas operations in Indian country. The 2010 permit for compressor stations located on the Southern Ute Indian Reservation (Florida River and Wolf Point) and the Summit Petroleum permits are two examples discussed in detail previously. In these cases, the EPA conducted a fact-specific examination of the three factors in determining which emitting activities should be included in title V permits. In both of these cases, the source determinations were challenged.

The EPA was challenged on its source determinations for the Florida River permit by WildEarth Guardians. They challenged the EPA's decision not to aggregate certain wells into a single source in the title V permit renewal. EPA entered into a settlement agreement with the petitioner and agreed to undertake a ''pilot'' program to gather additional information ''for the purpose of studying, improving and streamlining oil and gas source determinations in new or renewal Title V permits.'' [10] The EPA has collected data from several permit applicants, but has not yet issued permits based on that data, due to uncertainties created by court decisions discussed later in this proposal.

In the case of Summit Petroleum's operations in Rosemont, Michigan, also discussed previously, the EPA determined in 2010 that the company's gas sweetening facility and associated wells were under common control and in the same major industrial grouping. In addition, the EPA determined that they were adjacent because of the functional interrelatedness of the operations. The EPA determined that the source must get a title V operating permit.

Summit appealed that determination to the United States Court of Appeals for the Sixth Circuit, which issued a decision that overturned the EPA's title V applicability determination. *Summit Petroleum Corp.* v. *U.S. Environmental Protection Agency,* 690 F.3d 733 (6th Cir. 2012). In the decision, the Court said that the EPA's use of interrelatedness in determining whether sources were ''adjacent'' is unreasonable and contrary to the plain meaning of the term as currently used in EPA's regulations. The two judges in the majority found that the term ''adjacent'' was unambiguous and its plain meaning related only to physical proximity, and thus could not include consideration of functional interrelatedness. The EPA sought rehearing of the Court's decision, but that request was denied.

In a memorandum, EPA Headquarters then instructed its Regional Air Directors that the agency intended to apply the outcome of the Sixth Circuit decision only in the states under the jurisdiction of the Sixth Circuit and that we would continue to make stationary source determinations for title V and PSD permitting consistent with the agency's long-standing interpretations of its regulations in the rest of the country.[11]

The EPA's guidance memo to its regional offices was challenged by the National Environmental Development Association's Clean Air Project (NEDA/CAP) in the D.C. Circuit Court of

Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/oilgas.pdf* and in the docket for this rulemaking.

[9] McCarthy, Gina. ''Withdrawal of William Wehrum's January 12 2007 Issued Guidance Memo 'Source Determinations for Oil and Gas Industries'.'' September 22, 2009. EPA Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/oilgaswithdrawal.pdf* and in the docket for this rulemaking.

[10] U.S. Environmental Protection Agency. February 20, 2012. Motion for Dismissal. In re: BP America Production Company, Florida River Compression Facility, Permit No. V–SU–0022–05.00. Available at *http://yosemite.epa.gov/oa/EAB_Web_Docket.nsf/(Filings)/E340610E897366E1852579AB005443C4/$File/Motion%20for%20Dismissal...41.pdf* and in the docket for this rulemaking.

[11] Page, Stephen. ''Applicability of the Summit Decision to EPA Title V and NSR Source Determinations.'' December 21, 2012. EPA Region 7 Air Program New Source Review Program Policy & Guidance Index available at *http://www.epa.gov/region07/air/nsr/nsrmemos/inter2012.pdf* and in the docket for this rulemaking.

Appeals. *National Environmental Development Association's Clean Air Project* v. *Environmental Protection Agency,* 752 F.3d 999 (D.C. Cir. 2014). NEDA/CAP alleged that the memorandum violated the EPA's Regional Consistency regulations by establishing inconsistent permit criteria in different parts of the country. The D.C. Circuit agreed and held that the memo conflicted with EPA regulations that promote uniform national regulatory policies. 752 F.3d at 1009 (discussing 40 CFR part 56). In essence, the Court found that EPA bound itself to consistency with the *Summit* decision through its own regulations. In issuing the decision, the D.C. Circuit indicated that the EPA could have avoided a conflict between its December 2012 memo and the Regional Consistency regulations by revising the source determination regulations to explicitly require consideration of functional interrelatedness.

H. What is the purpose of this proposed action?

The purpose of this action is to request comment on the best approach to define ''adjacent'' for the onshore oil and natural gas sector.[12] We believe it is important to address this industry separately because permitting decisions are difficult and time-consuming. Providing this guidance will promote a consistent regulatory treatment for this industry. In addition, this industry continues to grow at a rapid pace, and the sheer number of determinations that need to be made heightens the need for guidance in the near term.

We also believe it is important to address this issue through a rulemaking. The oil and gas source determination guidance provided by the EPA on two separate occasions, in 2007 and 2009, was issued in the form of a memo, with no opportunity for public notice and comment. Then, as discussed above, the subsequent onshore oil and gas permitting decisions made by EPA were challenged, and both guidance memos were referenced or relied upon by the parties in those challenges. The EPA is interested in addressing any uncertainty by providing additional clarity through rulemaking and seeking comment on the best approach for defining the term ''adjacent'' specific to the onshore oil and natural gas sector.

[12] We note that the EPA Administrator signed a separate proposal on August 5, 2015 to amend the Regional Consistency Regulations to address consistency issues resulting from judicial decisions. *See* Environmental Protection Agency, RIN 2060–AS53 available at *http://www.epa.gov/nsr/actions.html.*

I. Policy Discussion

An important consideration in deciding how to define the stationary source for oil and gas operations is the environmental protection that is achieved by aggregating multiple pollutant-emitting activities into a single source. Under the PSD and NNSR programs, new major sources or major modifications at major sources for a given pollutant are subject to either Best Available Control Technology (BACT) or Lowest Achievable Emissions Reduction (LAER) controls, depending on the air quality designation status for that pollutant of the area in which the source is located. These controls may be more stringent than controls required at minor sources. Because major source BACT or LAER controls may be continually improving, permitting authorities must assess and sources must install the best technology at the time a permit is issued, instead of what was the best the last time an NSPS or NESHAP was updated. Therefore, these case-by-case controls required for major sources or major modifications at major sources are often more stringent than controls required under NSPS or NESHAP, if those standards have not been recently updated, because control technology tends to improve over time.

In addition, if the source is or will be located in an area that is designated nonattainment, emissions reductions, known as offsets, may be required in higher ratios to compensate for the proposed emissions increase. Therefore, aggregating activities into major sources may result in more oil and gas sources being subject to greater control under LAER, in addition to having to obtain offsets, resulting in greater environmental protection.

Aggregating facilities is also more likely to result in sources being subject to operating permitting requirements under title V of the Act. While this does not result in any additional control requirements, it may result in additional monitoring and reporting requirements that provide more information on the operation of the source to the regulators and interested citizens. The title V permitting process includes opportunities for public participation, EPA oversight, and citizens' rights to petition the EPA to object to permits. These opportunities exist at both the initial permit issuance, and at permit renewal, which occurs every 5 years. The title V process provides more opportunities for public participation than minor source permitting, which generally includes public participation only at the time of initial construction or modification, and under processes that vary according to the permitting authority.

Aggregating activities may also provide facility owners/operators with greater flexibility to modify operations without triggering additional permitting requirements. A source consisting of multiple emitting activities may be able to ''net out'' of further PSD or NNSR permit review by reducing emissions in one part of a source in order that emissions at another part of the source may increase. This allows sources to avoid additional permitting requirements for modifications to an existing facility under PSD and NNSR by taking credit for reductions that have already occurred within the facility. A smaller source offers less opportunity to ''net out'' because there are fewer emitting activities that can be reduced if a modification results in an increase. Finally, netting is usually not available under minor NSR programs, so smaller minor sources would likely not be able to take advantage of netting to avoid minor NSR permitting requirements.

Another approach to achieving environmental protection is to require controls by direct federal regulation through the NSPS or NESHAP programs. The NSPS program results in significant control and is applicable to new, modified and reconstructed sources. The NSPS also includes monitoring and recordkeeping requirements. The NESHAP program also results in significant control of HAP, many of which are also VOCs, and is applied to both new and existing sources. Each of the emissions standards established pursuant to these programs must be reviewed and revised, if necessary, at least every eight years to take into account developments in practices, processes and control technologies. These standards apply to affected facilities independent of the need for an NSR permit. Separately, the EPA is proposing revisions to 40 CFR part 60, subpart OOOO, the NSPS for the oil and natural gas sector.

Additional controls may be required for sources located in nonattainment areas, including minor sources, through a SIP, or through a Federal Implementation Plan (FIP) in areas where EPA is the regulatory authority, such as in certain areas of Indian country. The CAA requires implementation of reasonable available control technology (RACT) for major sources in moderate and above ozone nonattainment areas and in the Ozone Transport Region (OTR). The EPA develops Control Techniques Guidelines (CTGs) to inform a state's RACT determinations. Separately, the

EPA is proposing a CTG for the oil and natural gas sector.

All of these programs (NSPS, NESHAP, RACT and state SIP/EPA FIP requirements) typically apply to emitting equipment, irrespective of the total emissions of the source at which the equipment is located, although there may be thresholds for individual types of equipment. An advantage of applying environmental control through these programs is that the administrative burden of applying for, obtaining, and maintaining major source permits can be reduced for sources because these limitations establish enforceable limits on the sources' potential to emit, and can keep a source from being considered major. The burden of reviewing and issuing major source permits is likewise reduced for permitting authorities.

The biggest advantage to sources, particularly in this industry, is that controlling emissions through NSPS, NESHAP or emission control standards imposed by states through their SIPs does not require case-by-case pre-approval as do the controls determined through major source permitting. This provides greater certainty to the source owners and operators without the delays associated with such permitting. Communities can also be certain of the controls sources are required to install and operate because the sources do not have the opportunity to ''net out'' of controls through a permitting process. Compliance and enforcement are also enhanced because the control, monitoring and recordkeeping requirements are consistent for each type of equipment and do not differ from site to site, or in the case of federal controls, state to state.

For the oil and gas industry, where source owners/operators must obtain the right to drill in a particular location and only hold those rights for a limited period of time, the ability to proceed quickly is important. For communities and air regulators, the ability to protect air quality and public health is important. A major source permit typically takes a year or more to process. If there is uncertainty about what should be included as part of that permitted source, the time to issue a permit can take longer. We believe that the most important result of a major or minor permit for all stakeholders, including the regulated industry, the community in which the source is located, and the permitting authority, is the requirement to install control technology to minimize air emissions and protect public health and the environment. We think that providing clarity about the scope of the source through this rule, and the emissions control requirements associated with other rules being proposed by the EPA serves the interests of all stakeholders.

J. Why is the EPA proposing this action at this time?

One reason for taking this action is to resolve the uncertainty that the litigation over the Summit Petroleum source determination and resulting guidance has created for both permitting authorities and for owners/operators of regulated sources. Another reason is to develop a coordinated approach to regulating emissions from oil and gas sources under the variety of regulatory mechanisms available to state and federal regulatory agencies. There has been an increase in oil and gas production resulting from the rise in use of unconventional methods of extraction (*e.g.,* the use of hydraulic fracturing), and this production is taking place in more areas and at a faster pace than in the recent past. We believe this justifies a new look at the best way to regulate and permit these operations. In separate notices, the EPA is proposing to require additional controls for the emissions from the oil and natural gas sector. Those requirements include additional requirements for new sources under the NSPS, requirements for minor sources at oil and gas operations in Indian country, and a CTG that will inform RACT determinations for existing major VOC sources located in moderate or above ozone nonattainment areas and in the OTR.

We believe that the additional emissions controls required for new sources under the revised NSPS makes it less likely that major source permitting would result in substantial additional pollution control. In commenting on this proposal, commenters are encouraged to consider how emission controls being proposed in separate EPA notices may impact the preferred option in this proposal.

K. What is the effect of this proposed rulemaking on other industries?

At this time, the EPA is proposing to clarify the definition of ''adjacent'' used to determine the source to be permitted within the PSD, NNSR and title V programs as it applies to the oil and natural gas sector for the reasons discussed earlier in this proposal. The EPA believes that the unique characteristics of this industry—such as the underground mineral rights versus surface land ownership, widespread operations and interconnectedness via pipeline, etc.—warrant an industry-specific definition that will streamline the assessment of which operations should be considered to be on contiguous or adjacent properties. For other industries, we continue to believe that a case-by-case assessment of the three factors remains the appropriate method of making source determinations. For these industries, as discussed previously, we believe it is generally less difficult to determine the scope of the source, because the operations already take place at facilities that more clearly match the common sense notion of a plant.

L. What is the effect of this proposed rulemaking on permitting authorities?

We are proposing to make changes to both the PSD and NNSR programs in this rulemaking. We believe that it may be possible for some states to interpret their existing state rules consistent with this rulemaking (when final) and may not need to revise SIPs to incorporate these changes. However, we intend to encourage states to revise their SIPs to adopt these changes, when final. Similarly, states would be expected to make conforming changes to their operating permit programs. While we are proposing changes to both the federal programs and the requirements for state programs, we invite comment on whether states should be required to adopt these changes.

III. What are the options that the EPA is considering?

In this proposal, the EPA is proposing and requesting comment on two options for clarifying the definition used to determine the source to be permitted within the NSR and title V programs as it applies to the oil and natural gas sector. As we stated before, any determination of the scope of a source requires a fact-specific inquiry into each of the three regulatory factors, *i.e.,* whether emitting activities share the same SIC code, are under common control, and are contiguous or adjacent. We are not proposing to change or take comment on this inquiry or the three factors. However, in this notice, the EPA is taking comment on how the term ''adjacent'' in the third factor should be applied specifically to emission units in the oil and natural gas sector.

A. Define Source Based on Proximity (Similar to the NESHAP)

Under the first, and currently preferred, option for which the EPA is taking comment, the EPA proposes to define ''adjacent'' such that the source is similar to that in the NESHAP for this industry, Subpart HH, National Emissions Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities (40 CFR 63.760). Under this option, the ''source'' for oil and natural gas sector activities is presumed to be limited to the emitting activities at the surface site, and other emitting activities will be considered ''adjacent'' if they are proximate. Thus, under this first option, two or more surface sites must be considered as a single source if they share the same SIC code, are under common control, and are contiguous or are located within a short distance of one another.

We prefer this option because we believe that a definition that centers on a surface site is familiar to the industry and the regulators because of the current NESHAP requirements, so it will streamline permitting. We also believe that a definition focused on a surface site most closely represents the common sense notion of a plant for this industry category. Surface sites that are not in close proximity to one another may be on a separate lease which may not align with the common sense notion of a single plant. In addition, we believe that this definition is consistent with Congress' intent, at least as they expressed it with regard to HAPs, as discussed previously.

Under this option, as we are proposing it, the source owner/operator would not be required, and would not be allowed, to include additional emitting activities in a permit beyond those in the source as defined. This could mean that an owner/operator must obtain more individual construction permits and possibly more operating permits. However, these would be more likely to be minor source permits. If finalized, owner/operators could lose the benefits of being able to net emissions over a larger source, which could be a disadvantage, particularly for sources in nonattainment areas. We request comment on this more limited concept of source for this industry, specifically whether limiting the scope of the source in this way provides sufficient guidance for sources and permitting authorities to permit these sources in a consistent and efficient manner.

In addition, we request comment on whether it is appropriate to establish a specific distance within which to consider multiple surface sites as a single source, and if so, what that distance should be. Some states, such as Texas, Oklahoma, Louisiana and Pennsylvania, have issued guidance that presumes that operations within ¼ mile should be considered a single source. We believe that it will be helpful to prescribe a distance in this rule, given that this question has generated significant confusion and uncertainty in the past. The EPA is proposing to adopt a distance of ¼ mile but is asking for comment on whether another distance, such as ½ mile, is an appropriate distance to consider for defining a single source even if on separate surface sites (*i.e.,* operations beyond that distance would not be considered for aggregation).

Louisiana's guidance further specifies that facilities should not be ''daisy-chained'' together to establish a single contiguous source.[13] A series of emission units are ''daisy-chained'' when each individual unit is located within the specified ''contiguous or adjacent'' distance from the next unit, but where the last unit is separated from the first unit by a much larger distance. We request comment on whether the EPA should make a similar distinction if we adopt this proximity-focused source definition. Louisiana's guidance goes on to specify that the geographic center of the site's emissions defines the center for purposes of establishing the ¼ mile distance used to determine the boundary of the single source. We request comment on whether the center or some other feature, such as the boundary of the surface site, is more appropriate to use as the starting point of the measurement radius when determining the source.

We also request comment on whether there are instances where setting such a bright-line distance could increase or limit permitting authority oversight of these sources because they would be more likely to be subject to minor source permitting. We also request comment on whether the potentially smaller scope of each source could result in an unacceptable permitting burden (by creating a larger number of smaller sources) on the regulated community or on permitting authorities.

While the EPA does not expect there would be adverse air quality impacts as a result of this approach, we are interested in whether there might be any environmental effect, including effects on NAAQS compliance from this approach, with either benefit or harm resulting. Finally, we request comment on whether there are circumstances in which an owner/operator would prefer to combine surface sites or other operations that are beyond the presumptive distance, *e.g.,* ¼ mile, and seek a PSD or NNSR permit, and whether the EPA should preserve this option. If so, should the option to seek a major source permit be limited to the owner or operator's discretion, or should a permitting authority be able to make this determination, and under what circumstances?

B. Define Source To Include Exclusively Functionally Interrelated Equipment

Under the second option, the EPA proposes to define the ''source'' for the oil and natural gas sector to include all of the interrelated equipment that is under common control, is in the two-digit SIC (Code 13 Oil and Gas Extraction), and is on contiguous or adjacent property, where the EPA would presume that equipment in an oil and gas field is ''adjacent'' if it is proximate, or if it is exclusively functionally interrelated. Exclusive functional interrelatedness might be shown by connection via a pipeline or other means, because of the physical connection between the equipment. Other examples of factors that could be assessed to determine interrelatedness include exclusive delivery of product from one group of equipment to the other via truck or train and facts such as whether one group of equipment would be able to operate if the other group of equipment was not operating. The EPA and states would make a determination of adjacency based on a consideration of the interrelatedness of emitting activities in addition to the distance between them. So, for the oil and natural gas sector, pollutant-emitting activities will be considered adjacent if one of the following circumstances apply: (1) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or (2) the pollutant-emitting activities are separated by a distance of less than ¼ mile.

The consideration of interrelatedness is consistent with the EPA's current and historical practice for other industries and its longstanding practice for oil and natural gas sector activities. The EPA is requesting comment on this approach to better understand the perspective of various stakeholders. What are the advantages and disadvantages to this approach? Are there characteristics related to the oil and natural gas sector that would make this approach more or less difficult to implement than the preferred alternative, such as need to examine various interrelatedness criteria or the interconnectedness of the operations through pipelines? Should the EPA further define exclusive functional interrelatedness for this sector to provide additional clarity to regulators and the regulated community? For example, should the

[13] Louisiana Department of Environmental Quality. *Interpretation of Contiguous for Oil & Gas Production Facilities. http://www.deq.louisiana.gov/portal/DIVISIONS/AirPermitsEngineeringandPlanning/AirPermitsProceduresandGuidance/ContiguityandOilandGasProduction.aspx.* March 2015.

EPA limit exclusive functional interrelatedness for this sector to emitting equipment that is configured in a ''hub and spoke'' model, where oil or gas produced from one or more wells has a dedicated flow (via a pipeline or other delivery method) to only one possible downstream point for further compression, processing or storage? Are there other configurations specific to this industry that the EPA should consider to be exclusively functionally interrelated?

In addition, is there any environmental benefit or harm that might result from this approach? For example, could this approach create a disincentive to building pipelines, and what would be the environmental effect of those decisions? Finally, the EPA requests comment on whether there is a specific distance beyond which sources in the oil and gas industry should not be considered interrelated, even if interconnected by pipeline.

C. Impacts of the Options on Air Permitting

The EPA expects that the combined effect of all the rules being proposed, including the proposed changes to the NSPS, the proposed rule for oil and gas sources in Indian country, and the CTG, will be to reduce the number of major oil and gas sources, even if we finalize Option 2. The proposed rules add requirements for enforceable controls, thereby decreasing potential emissions and making it less likely that major source permitting will be required. This is because a source's potential emissions are determined after taking into account controls that are enforceable as a practical matter, such as those required in the NSPS and a SIP adopting the CTG.

The two options presented in this rule differ primarily in the permitting burden placed on sources and permitting authorities. In the EPA's experience, it takes significantly longer to apply for and review a PSD application than it does to apply for and review a minor NSR permit. Option 1 can be expected to result in fewer major sources than Option 2, but more minor sources. Option 2 can be expected to result in more major sources, as some otherwise minor sources could be combined into a smaller number of major sources.

Because the EPA would benefit from public comment on all of these issues, the EPA is co-proposing these two approaches and, following review of public comments on the issues raised by each approach, anticipates adopting one of the approaches in the final rule. We welcome comments on these two discrete options, or some combination of these, and other options for determining the source for permitting oil and natural gas sector operations.

D. Proposal is Limited to Onshore Oil and Gas Operations

The EPA is proposing to limit this rulemaking to onshore oil and gas operations for a number of reasons. First, the CAA already contains a specific definition of ''outer continental shelf source'' which includes any ''equipment activity, or facility which emits or has the potential to emit any air pollutant'' specifically including ''platform and drill ship exploration, construction, development, production, processing, and transportation.'' In addition, ''emissions from any vessel servicing or associated with an outer continental shelf (OCS) source, including emissions while at the OCS source or en route to or from the OCS source within 25 miles of the OCS source'' must be included when determining the OCS source [CAA section 328(a)(4)(C)]. In our permitting experience, these OCS sources are more likely than onshore operations to be stand-alone major PSD sources. The EPA has issued permits for exploration rigs to operate as portable PSD sources, allowing them to operate in a number of locations under one permit. We believe that this current approach provides sufficient streamlining for both sources and permitting authorities and propose to continue the existing case-by-case approach for offshore sources.

IV. Environmental Justice Considerations

This proposal is intended to clarify the definition of adjacent used to determine the source to be permitted within the existing PSD, NNSR and title V programs as it applies to the oil and natural gas sector. This clarification will assist permitting authorities and permit applicants in making source determinations for the oil and gas industry and is not intended to result in less environmental protection for human health and the environment. It is being proposed as a part of a comprehensive strategy to reduce emissions from the oil and natural gas production sector which includes new (or lower) emission standards or requirements for a number of types of emitting equipment. It, therefore, is not expected to have a disproportionately high and adverse human health or environmental effects on minority populations or low-income populations. However, the permitting process, particularly under the major source programs, NSR and title V, may provide opportunities for public participation at individual sources that may be of interest to minority or low-income populations.

V. Statutory and Executive Order Reviews

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This proposed action is a significant regulatory action that was submitted to the Office of Management and Budget (OMB) for review because it raises novel legal and policy issues arising out of the President's priorities. Any changes made in response to OMB recommendations have been documented in the docket.

B. Paperwork Reduction Act

This proposed action would not impose any new information collection burden. However, the OMB has previously approved the information collection requirements contained in the existing regulations for PSD (40 CFR 52.21) and title V (40 CFR parts 70 and 71) under the provisions of the *Paperwork Reduction Act,* 44 U.S.C. 3501 *et seq* and has assigned OMB control numbers 2060–0003, 2060–0336 and 2060–0243. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. Instead of new information collection burdens, this proposed action proposes proffers options that clarify the existing permitting requirements applicable to new and modified oil and natural gas sector sources. This proposed action is not likely to increase the burden associated with permitting, and may reduce it.

C. Regulatory Flexibility Act

The Regulatory Flexibility Act (RFA) generally requires an agency to prepare a regulatory flexibility analysis of any regulation subject to notice and comment rulemaking requirements under the Administrative Procedures Act or any other statute unless the agency certifies the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations and small governmental jurisdictions.

For purposes of assessing the impacts of this proposed rule on small entities, small entity is defined as: (1) A small business as defined in the Small Business Administration's (SBA) regulations at 13 CFR 121.201; (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.

After considering the economic impacts of this proposed rule on small entities, I certify that this proposed action will not have a significant economic impact on a substantial number of small entities. In making this determination, the impact of concern is any significant adverse economic impact on small entities. An agency may certify that a rule will not have a significant economic impact on a substantial number of small entities if the rule relieves regulatory burden, has no net burden or otherwise has a positive economic effect on the small entities subject to the rule. Entities potentially affected directly by this proposal include sources in the oil and natural gas sector. We intend with this proposal to clarify the existing requirements for permitting new and existing sources in the oil and natural gas sector. We believe that any option finalized after notice and comment rulemaking will not increase, and may decrease, the administrative burden for permitting these sources, including those that may be small entities. We have, therefore, concluded that this proposed action will have no net regulatory burden for all directly regulated small entities.

We continue to be interested in the potential impacts of the proposed rule on small entities and welcome comments on issues related to such impacts.

D. Unfunded Mandates Reform Act

This proposed action does not contain an unfunded mandate of $100 million or more as described in the Unfunded Mandates Reform Act of 1995 (UMRA), 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. This action imposes no enforceable duty on any state, local or tribal governments or the private sector. The CAA imposes the obligation for private sector sources to obtain permits prior to construction. Many states and some local governments choose to implement those requirements. In other areas, the EPA implements those requirements. In this proposal, the EPA is taking comment on the most appropriate way to implement those requirements for an industry category. Therefore, this proposed action is not subject to the requirements of sections 202, 203 and 205 of the UMRA.

E. Executive Order 13132: Federalism

This proposed action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government, as specified in Executive Order 13132. The requirement to obtain permits for new major sources is imposed by the CAA. This proposed rule, if made final, would interpret those requirements as they apply to the oil and natural gas sector. Thus, Executive Order 13132 does not apply to these proposed regulation revisions.

In the spirit of Executive Order 13132 and consistent with the EPA policy to promote communications between the EPA and state and local governments, the EPA specifically solicits comments on this proposed action from state and local officials.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications as specified in Executive Order 13175. It would not have a substantial direct effect on one or more Indian tribes, since no tribe has developed a TIP that allows it to issue NSR permits. Furthermore, these proposed regulation revisions do not affect the relationship or distribution of power and responsibilities between the federal government and Indian tribes. The CAA and the Tribal Air Rule establish the relationship of the federal government and tribes in developing plans to implement NSR permitting, and this proposal does nothing to modify that relationship. Thus, Executive Order 13175 does not apply to this action.

The EPA has concluded that this action will not have tribal implications because it doesn't impose a significant cost to tribal governments. However, there are significant tribal interests because of the growth of the oil and gas production industry in Indian country. Although Executive Order 13175 does not apply to this action, the EPA has offered consultation to tribal officials in developing this action. Meeting summaries will be included in the docket for this rulemaking.

The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health and Safety Risks

The EPA interprets EO 13045 as applying only to those regulatory actions that concern environmental health or safety risks that the EPA has reason to believe may disproportionately affect children. This action is not subject to EO 13045 because it is not intended to establish an environmental standard intended to mitigate health or safety risks. The proposal requests comments on the appropriate definition of a source as it applies to one source category for purposes of permitting under the requirements of the CAA.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

This proposed action is not a ''significant energy action'' because it is not likely to have a significant adverse effect on the supply, distribution or use of energy. We believe this action is not likely to have any adverse energy effects because it will not increase, and may decrease, the permitting burden on owners and operators of sources in the oil and natural gas sector.

I. National Technology Transfer and Advancement Act

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113, section 12(d) (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 and business practices) that are developed or adopted by voluntary consensus standards bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the agency decides not to use available and applicable voluntary consensus standards.

This proposed rulemaking does not involve technical standards. Therefore, the EPA is not considering the use of any voluntary consensus standards.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this proposed action will not have disproportionately high and adverse human health or environmental effects on minority, low-income populations or indigenous populations. The proposal requests comment on the appropriate definition of the source as it applies to one industry category for purposes of permitting under the CAA. As such, it does not adversely affect the health or safety of minority or low-income populations. The results of this evaluation are contained in Section IV of this preamble.

K. Determination Under Section 307(d)

Pursuant to sections 307(d)(1)(J) and 307(d)(1)(V) of the CAA, the Administrator determines that this action is subject to the provisions of section 307(d). Under section 307(d)(1)(J), the provisions of section 307(d) apply to revisions to regulations relating to PSD. Under section 307(d)(1)(V), the provisions of section 307(d) apply to ''such other actions as the Administrator may determine.''

Statutory Authority

The statutory authority for this action is provided by sections 101; 111; 114; 116, 160–165, 169, 173, 301, 302, 501 and 502 of the CAA, as amended (42 U.S.C. 7401; 42 U.S.C. 7411; 42 U.S.C. 7414; 42 U.S.C. 7416; 7470–7475, 7479, 7503, 7601, 7602, 7661, and 7662.

List of Subjects

40 CFR Part 51

Environmental protection, Air pollution control, Construction permit, Intergovernmental relations, Major source, Oil and gas.

40 CFR Part 52

Environmental protection, Air pollution control, Construction permit, Incorporation by reference, Intergovernmental relations, Major source, Oil and gas.

40 CFR Part 70

Environmental protection, Air pollution control, Intergovernmental relations, Major source, Oil and gas, Operating permit.

40 CFR Part 71

Environmental protection, Administrative practice and procedure, Air pollution control, Intergovernmental relations, Major source, Operating permit.

Dated: August 18, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, Title 40, Chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 51—REQUIREMENTS FOR PREPARATION, ADOPTION, AND SUBMITTAL OF IMPLEMENTATION PLANS

■ 1. The authority citation for part 51 continues to read as follows:

Authority: 23 U.S.C. 101; 42 U.S.C. 7401–7671q.

■ 2. In § 51.165, revise paragraph (a)(1)(ii) to read as follows:

§ 51.165 Permit requirements.

(a) * * *

(1) * * *

[PROPOSED REGULATORY TEXT FOR OPTION 1]

(ii) (A) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered as part of the same industrial grouping if they belong to the same *Major Group* (*i.e.,* which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0065 and 003–005–00176–0, respectively).

(B) Notwithstanding the provisions of paragraph (a)(1)(ii)(A) of this section, *building, structure, facility, or installation* means, for onshore activities under SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13 that are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

(ii) (A) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered as part of the same industrial grouping if they belong to the same *Major Group* (*i.e.,* which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0065 and 003–005–00176–0, respectively).

(B) Notwithstanding the provisions of paragraph (a)(1)(ii)(A) of this section, *building, structure, facility, or installation* means, for onshore activities in SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered adjacent if one of the following circumstances apply:

(*1*) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(*2*) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

■ 3. In § 51.166, revise paragraph (b)(6) to read as follows:

§ 51.166 Prevention of significant deterioration of air quality.

* * * * *

(b) * * *

[PROPOSED REGULATORY TEXT FOR OPTION 1]

(6)(i) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same *Major Group* (*i.e.,* which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(ii) Notwithstanding the provisions of paragraph (b)(6)(i) of this section, *building, structure, facility, or installation* means, for onshore activities under SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13 that are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

(6)(i) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same *Major Group* (*i.e.,* which have the same two-digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(ii) Notwithstanding the provisions of paragraph (b)(6)(i) of this section, *building, structure, facility, or installation* means, for onshore activities in SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered adjacent if one of the following circumstances apply:

(*A*) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(*B*) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

■ 4. In appendix S to part 51, revise section A.2. to read as follows:

APPENDIX S TO PART 51—EMISSION OFFSET INTERPRETATIVE RULING

* * * * *

II. Initial Screening Analyses and Determination of Applicable Requirements

A. * * *

[PROPOSED REGULATORY TEXT FOR OPTION 1]

2. (i) *Building, structure, facility or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same two digit code) as described in the *Standard Industrial Classification Manual,* 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(ii) Notwithstanding the provisions of paragraph II.2.(i) of this appendix, *building, structure, facility or installation* means, for onshore activities under SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13 that are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

2. (i) *Building, structure, facility or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same two digit code) as described in the *Standard Industrial Classification Manual,* 1972, as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00176–0, respectively).

(ii) Notwithstanding the provisions of paragraph II.2.(i) of this appendix, *building, structure, facility or installation* means, for onshore activities in SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered adjacent if one of the following circumstances apply:

(A) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(B) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

PART 52—APPROVAL AND PROMULGATION OF IMPLEMENTATION PLANS

■ 5. The authority citation for part 52 continues to read as follows:

Authority: 42 U.S.C. 7401 *et seq.*

■ 6. In § 52.21, revise paragraph (b)(6) to read as follows:

§ 52.21 Prevention of significant deterioration of air quality.

* * * * *

(b)* * *

[PROPOSED REGULATORY TEXT FOR OPTION 1]

(6)(i) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00716–0, respectively.

(ii) Notwithstanding the provisions of paragraph (b)(6)(i) of this section, *building, structure, facility, or installation* means, for onshore activities under SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13 that are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

(6)(i) *Building, structure, facility, or installation* means all of the pollutant-emitting activities which belong to the same industrial grouping, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control) except the activities of any vessel. Pollutant-emitting activities shall be considered as part of the same industrial grouping if they belong to the same ''Major Group'' (*i.e.,* which have the same first two digit code) as described in the *Standard Industrial Classification Manual, 1972,* as amended by the 1977 Supplement (U.S. Government Printing Office stock numbers 4101–0066 and 003–005–00716–0, respectively.

(ii) Notwithstanding the provisions of paragraph (b)(6)(i) of this section, *building, structure, facility, or installation* means, for onshore activities in SIC Major Group 13: Oil and Gas Extraction, all of the pollutant-emitting activities included in Major Group 13, are located on one or more contiguous or adjacent properties, and are under the control of the same person (or persons under common control). Pollutant-emitting activities shall be considered adjacent if one of the following circumstances apply:

(A) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(B) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

PART 70—STATE OPERATING PERMIT PROGRAMS

■ 7. The authority citation for part 70 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

■ 8. In § 70.2, revise the undesignated text of the definition for ''Major source'' to read as follows:

§ 70.2 Definitions.

[PROPOSED REGULATORY TEXT FOR OPTION 1]

* * * * *

Major source means any stationary source (or any group of stationary sources that are located on one or more continuous or adjacent properties, and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining ''major source,'' a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to SIC Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or are on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

* * * * *

■ 9. In § 70.2, revise the undesignated text, and paragraphs 1 and 2 of the definition for ''Major source'' to read as follows:

§ 70.2 Definitions.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

* * * * *

Major source means any stationary source (or any group of stationary sources that are located on one or more continuous or adjacent properties, and are under common control of the same person (or persons under common control)) belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining ''major source,'' a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to SIC Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if one of the following circumstances apply:

(1) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(2) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

PART 71—FEDERAL OPERATING PERMIT PROGRAMS

■ 10. The authority citation for part 71 continues to read as follows:

Authority: 42 U.S.C. 7401, *et seq.*

Subpart A—Operating Permits

■ 11. In § 71.2, revise the undesignated text of the definition for ''Major sources'' to read as follows:

§ 71.2 Definitions.

[PROPOSED REGULATORY TEXT FOR OPTION 1]

* * * * *

Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining ''major source,'' a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to SIC Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if they are located on the same surface site, or are on surface sites that are located within ¼ mile of one another, where a surface site has the same meaning as in 40 CFR 63.761.

* * * * *

■ 12. In § 71.2, revise the undesignated text, and paragraphs 1 and 2 of the definition for ''Major sources'' to read as follows:

§ 71.2 Definitions.

[PROPOSED REGULATORY TEXT FOR OPTION 2]

* * * * *

Major source means any stationary source (or any group of stationary sources that are located on one or more contiguous or adjacent properties, and are under common control of the same person (or persons under common control)), belonging to a single major industrial grouping and that are described in paragraph (1), (2), or (3) of this definition. For the purposes of defining ''major source,'' a stationary source or group of stationary sources shall be considered part of a single industrial grouping if all of the pollutant emitting activities at such source or group of sources on contiguous or adjacent properties belong to the same Major Group (*i.e.,* all have the same two-digit code) as described in the Standard Industrial Classification Manual, 1987. For onshore activities belonging to SIC Major Group 13: Oil and Gas Extraction, pollutant emitting activities shall be considered adjacent if one of the following circumstances apply:

(1) The pollutant-emitting activities are separated by a distance of ¼ mile or more and there is an exclusive functional interrelatedness; or

(2) The pollutant-emitting activities are separated by a distance of less than ¼ mile.

* * * * *

[FR Doc. 2015–21026 Filed 9–17–15; 8:45 am]

BILLING CODE 6560–50–P

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 60

[EPA–HQ–OAR–2010–0505; FRL–9929–75–OAR]

RIN 2060–AS30

Oil and Natural Gas Sector: Emission Standards for New and Modified Sources

AGENCY: Environmental Protection Agency (EPA).

ACTION: Proposed rule.

SUMMARY: This action proposes to amend the new source performance standards (NSPS) for the oil and natural gas source category by setting standards for both methane and volatile organic compounds (VOC) for certain equipment, processes and activities across this source category. The Environmental Protection Agency (EPA) is including requirements for methane emissions in this proposal because methane is a greenhouse gas (GHG), and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations. The EPA is proposing both methane and VOC standards for several emission sources not currently covered by the NSPS and proposing methane standards for certain emission sources that are currently regulated for VOC. The proposed amendments also extend the current VOC standards to the remaining unregulated equipment across the source category and additionally establish methane standards for this equipment. Lastly, amendments to improve implementation of the current NSPS are being proposed which result from reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, final NSPS for the oil and natural gas sector and related amendments. Except for the implementation improvements and the setting of standards for methane, these amendments do not change the requirements for operations already covered by the current standards.

DATES: Comments. Comments must be received on or before November 17, 2015. Under the Paperwork Reduction Act(PRA), comments on the information collection provisions are best assured of consideration if the Office of Management and Budget (OMB) receives a copy of your comments on or before November 17, 2015. The EPA will hold public hearings on the proposal. Details will be announced in a separate announcement.

ADDRESSES: Submit your comments, identified by Docket ID Number EPA–HQ–OAR–2010–0505, to the Federal eRulemaking Portal: *http://www.regulations.gov.* Follow the online instructions for submitting comments. Once submitted, comments cannot be edited or withdrawn. The EPA may publish any comment received to its public docket. Do not submit electronically any information you consider to be Confidential Business Information (CBI) or other information whose disclosure is restricted by statute. Multimedia submissions (audio, video, etc.) must be accompanied by a written comment. The written comment is considered the official comment and should include discussion of all points you wish to make. The EPA will generally not consider comments or comment contents located outside of the primary submission (i.e. on the web, cloud, or other file sharing system). For additional submission methods, the full EPA public comment policy, information about CBI or multimedia submissions, and general guidance on making effective comments, please visit *http://www2.epa.gov/dockets/commenting-epa-dockets.*

Instructions: All submissions must include agency name and respective docket number or Regulatory Information Number (RIN) for this rulemaking. Direct your comments to Docket ID Number EPA–HQ–OAR–2010–0505. The EPA's policy is that all comments received will be included in the public docket without change and may be made available online at *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. (See section III.B below for instructions on submitting information claimed as CBI.) The *www.regulations.gov* Web site is an ''anonymous access'' system, which means the EPA will not know your identity or contact information unless you provide it in the body of your comment. If you submit an electronic comment through *www.regulations.gov,* the EPA recommends that you include your name and other contact information in the body of your comment and with any disk or CD–ROM you submit. If the EPA cannot read your comment due to technical difficulties and cannot contact you for clarification, the EPA may not be able to consider your comment. If you send an email comment directly to the 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. 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 the EPA's public docket, visit the EPA Docket Center homepage at: *www.epa.gov/epahome/dockets.htm.*

Docket: The EPA has established a docket for this rulemaking under Docket ID Number EPA–HQ–OAR–2010–0505. All documents in the docket are listed in the *www.regulations.gov* index. Although listed in the index, some information is not publicly available, *e.g.,* CBI or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy. Publicly available docket materials are available either electronically in *www.regulations.gov* or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 1301 Constitution Avenue NW., Washington, DC. The Public Reading Room is open from 8:30 a.m. to 4:30 p.m., Monday through Friday, excluding legal holidays. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the EPA Docket Center is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For information concerning this action, or for other information concerning the EPA's Oil and Natural Gas Sector regulatory program, contact Mr. Bruce Moore, Sector Policies and Programs Division (E143–05), Office of Air Quality Planning and Standards, Environmental Protection Agency, Research Triangle Park, North Carolina 27711, telephone number: (919) 541–5460; facsimile number: (919) 541–3470; email address: *moore.bruce@epa.gov.*

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I. Preamble Acronyms and Abbreviations

Several acronyms and terms are included in this preamble. While this may not be an exhaustive list, to ease the reading of this preamble and for reference purposes, the following terms and acronyms are defined here:

ANGA America's Natural Gas Alliance
API American Petroleum Institute
bbl Barrel
BID Background Information Document
BOE Barrels of Oil Equivalent
bpd Barrels Per Day
BSER Best System of Emissions Reduction
BTEX Benzene, Toluene, Ethylbenzene and Xylenes
CAA Clean Air Act
CFR Code of Federal Regulations
CPMS Continuous Parametric Monitoring Systems
EIA Energy Information Administration
EPA Environmental Protection Agency
GOR Gas to Oil Ratio
HAP Hazardous Air Pollutants
HPD HPDI, LLC
LDAR Leak Detection and Repair
Mcf Thousand Cubic Feet
NEI National Emissions Inventory
NEMS National Energy Modeling System
NESHAP National Emissions Standards for Hazardous Air Pollutants
NSPS New Source Performance Standards
NTTAA National Technology Transfer and Advancement Act of 1995
OAQPS Office of Air Quality Planning and Standards
OGI Optical Gas Imaging
OMB Office of Management and Budget
OVA Olfactory, Visual and Auditory
PRA Paperwork Reduction Act
PTE Potential to Emit
REC Reduced Emissions Completion
RFA Regulatory Flexibility Act
RIA Regulatory Impact Analysis
scfh Standard Cubic Feet per Hour
scfm Standard Cubic Feet per Minute
SISNOSE Significant Economic Impact on a Substantial Number of Small Entities
tpy Tons per Year
TSD Technical Support Document
TTN Technology Transfer Network
UMRA Unfunded Mandates Reform Act
VCS Voluntary Consensus Standards
VOC Volatile Organic Compounds
VRU Vapor Recovery Unit

II. Executive Summary

A. Purpose of the Regulatory Action

The purpose of this action is to propose amendments to the NSPS for the oil and natural gas source category. To date the EPA has established standards for emissions of VOC and sulfur dioxide (SO_2) for several operations in the source category. In this action, the EPA is proposing to amend the NSPS to include standards for reducing methane as well as VOC emissions across the oil and natural gas source category (*i.e.,* production, processing, transmission and storage). The EPA is including requirements for methane emissions in this proposal because methane is a GHG and the oil and natural gas category is currently one of the country's largest emitters of methane. In 2009, the EPA found that by causing or contributing to climate change, GHGs endanger both the public health and the public welfare of current and future generations.1 The proposed amendments would require reduction of methane as well as VOC across the source category.

In addition, the proposed amendments include improvements to several aspects of the existing standards related to implementation. These improvements and the setting of standards for methane are a result of reconsideration of certain issues raised in petitions for reconsideration that were received by the Administrator on the August 16, 2012, NSPS (77 FR 49490) and on the September 13, 2013, amendments (78 FR 58416). Except for these implementation improvements, these proposed amendments do not change the requirements for operations and equipment already covered by the current standards.

B. Summary of the Major Provisions of the Regulatory Action

The proposed amendments include standards for methane and VOC for certain new, modified and reconstructed equipment, processes and activities across the oil and natural gas source category. These emission sources include those that are currently unregulated under the current NSPS (hydraulically fractured oil well completions, pneumatic pumps and fugitive emissions from well sites and compressor stations); those that are currently regulated for VOC but not for methane (hydraulically fractured gas well completions, equipment leaks at natural gas processing plants); and certain equipment that are used across the source category, but which the current NSPS regulates VOC emissions from only a subset of these equipment (pneumatic controllers, centrifugal compressors, reciprocating compressors), with the exception of compressors located at well sites.

Based on the EPA's analysis (see section VIII), we believe it is important to regulate methane from the oil and gas sources already regulated for VOC emissions to provide more consistency across the category, and that the best system of emission reduction (BSER) for methane for all these sources is the same as the BSER for VOC. Accordingly, the current VOC standards also reflect the BSER for methane reduction for the same emission sources. In addition, with respect to equipment used category-wide of which only a subset of those equipment are covered under the NSPS VOC standards (i.e., pneumatic controllers, and compressors located other than at well sites), EPA's analysis shows that the BSER for reducing VOC from the remaining unregulated equipment to be the same as the BSER for those currently regulated. The EPA is therefore proposing to extend the current VOC standards for these equipment to the remaining unregulated equipment.

The additional sources for which we are proposing methane and VOC standards were evaluated in the 2014 white papers (EPA Docket Number EPA–HQ–OAR–2014–0557). The papers summarized the EPA's understanding of VOC and methane emissions from these sources and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The information gained through this process has improved the EPA's understanding of the methane and VOC emissions from these sources and the mitigation techniques available to control them.

The EPA has also received extensive and helpful input from state, local and tribal governments experienced in these operations, industry organizations, individual companies and others with data and experience. This information has been immensely helpful in determining appropriate standards for the various sources we are proposing to regulate. It has also helped the EPA design this proposal so as to complement, not complicate, existing state requirements. EPA acknowledges that a state may have more stringent state requirements (*e.g.*, fugitives monitoring and repair program). We believe that affected sources already complying with more stringent state requirements may also be in compliance with this rule. We solicit comment on how to determine whether existing state requirements (*i.e.*, monitoring, record keeping, and reporting) would demonstrate compliance with this federal rule.

During development of these proposed requirements, we were mindful that some facilities that will be subject to the proposed EPA standards will also be subject to current or future requirements of the Department of Interior's Bureau of Land Management (BLM) rules covering production of natural gas on Federal lands. We believe, to minimize confusion and unnecessary burden on the part of owners and operators, it is important that the EPA requirements not conflict with BLM requirements. As a result, EPA and BLM have maintained an ongoing dialogue during development of this action to identify opportunities for alignment and ways to minimize potential conflicting requirements and will continue to coordinate through the agencies' respective proposals and final rulemakings.

Following are brief summaries of these sources and the proposed standards.

Compressors. The EPA is proposing a 95 percent reduction of methane and VOC emissions from wet seal centrifugal compressors across the source category (except for those located at well sites).[2] For reciprocating compressors across the source category (except for those located at well sites), the EPA is proposing to reduce methane and VOC emissions by requiring that owners and/or operators of these compressors replace the rod packing based on specified hours of operation or elapsed calendar months or route emissions from the rod packing to a process through a closed vent system under negative pressure. See sections VIII.B and C of this preamble for further discussion.

Pneumatic controllers. The EPA is proposing a natural gas bleed rate limit of 6 standard cubic feet per hour (scfh) to reduce methane and VOC emissions from individual, continuous bleed, natural gas-driven pneumatic controllers at locations across the source category other than natural gas processing plants. At natural gas processing plants, the proposed rule regulates methane and VOC emissions by requiring natural gas-operated pneumatic controllers to have a zero natural gas bleed rate, as in the current NSPS. See section VIII.D of this preamble for further discussion.

Pneumatic pumps. The proposed standards for pneumatic pumps would apply to certain types of pneumatic pumps across the entire source category. At locations other than natural gas processing plants, we are proposing that the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps be reduced by 95 percent if a control device is already available on site. At natural gas processing plants, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero. See section VIII.E of this preamble for further discussion.

Hydraulically fractured oil well completions. For subcategory 1 wells (non-wildcat, non-delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use reduced emissions completions, also known as ''RECs'' or ''green completions,'' to reduce methane and VOC emissions and maximize natural gas recovery from well completions. To achieve these reductions, owners and operators of hydraulically fractured oil wells must use RECs in combination with a completion combustion device. As is specified in the rule for hydraulically fractured gas well completions, the rule proposed here does not require RECs where their use is not feasible (*e.g.*, if it technically infeasible for a separator to function). For subcategory 2 wells (wildcat and delineation wells), we are proposing that for hydraulically fractured oil well completions, owners and/or operators use a completion combustion device to reduce methane and VOC emissions. The proposed standards for hydraulically fractured oil well completions are the same as the requirements finalized for hydraulically fractured gas well completions in the 2012 NSPS and as amended in 2014 (see 79 FR 79018, December 31, 2014). See section VIII.F of this preamble for further discussion.

Fugitive emissions from well sites and compressor stations. We are proposing that new and modified well sites and compressor stations (which include the transmission and storage segment and the gathering and boosting segment) conduct fugitive emissions surveys

[2] During the development of the 2012 NSPS, our data indicatedd that there were no centrifugal compressors located at well sites. Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

semiannually with optical gas imaging (OGI) technology and repair the sources of fugitive emissions within 15 days that are found during those surveys. We are also co-proposing OGI monitoring surveys on an annual basis for new and modified well sites, and requesting comment on OGI monitoring surveys on a quarterly basis for both well sites and compressor stations. Fugitive emissions can occur immediately on startup of a newly constructed facility as a result of improper makeup of connections and other installation issues. In addition, during ongoing operation and aging of the facility, fugitive emissions may occur. Under this proposal, the required survey frequency would decrease from semiannually to annually for sites that find fugitive emissions from fewer than one percent of their fugitive emission components during a survey, while the frequency would increase from semiannually to quarterly for sites that find fugitive emissions from three percent or more of their fugitive emission components during a survey. We recognize that subpart W already requires annual fugitives reporting for certain compressor stations that exceed the 25,000 Metric Ton CO_2e threshold, and request comments on the overlap of these reporting requirements.

Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. Based on this concept, we solicit comment on criteria we can use to determine whether and under what conditions well sites and other emission sources operating under corporate fugitive monitoring plans can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

Other reconsideration issues being addressed. The EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues are as follows: Storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, flare design and operation standards, leak detection and repair (LDAR) for open-ended valves or lines, compliance period for LDAR for newly affected units, exemption to notification requirement for reconstruction, disposal of carbon from control devices, the definition of capital expenditure and initial compliance clarification. We are proposing to address these issues to clarify the rule, improve implementation and update procedures, as fully detailed in section IX.

C. Costs and Benefits

The EPA has estimated emissions reductions, costs and benefits for two years of analysis: 2020 and 2025. Actions taken to comply with the proposed NSPS are anticipated to prevent significant new emissions, including 170,000 to 180,000 tons of methane, 120,000 tons of VOC and 310 to 400 tons of hazardous air pollutants (HAP) in 2020. The emission reductions are 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP in 2025. The methane-related monetized climate benefits are estimated to be $200 to $210 million in 2020 and $460 to $550 million in 2025 using a 3 percent discount rate (model average).[3]

In addition to the benefits of methane reductions, stakeholders and members of local communities across the country have reported to the EPA their significant concerns regarding potential adverse effects resulting from exposure to air toxics emitted from oil and natural gas operations. Importantly, this includes disadvantaged populations.

The measures proposed in this action achieve methane and VOC reductions through direct regulation. The hazardous air pollutant (HAP) reductions from these proposed standards will be meaningful in local communities. In addition, reduction of VOC emissions will be very beneficial in areas where ozone levels approach or exceed the National Ambient Air Quality Standards for ozone. There have been measurements of increasing ozone levels in areas with concentrated oil and natural gas activity, including Wyoming and Utah. Several VOCs that commonly are emitted in the oil and natural gas source category are HAPs listed under Clean Air Act (CAA) section 112(b), including benzene, toluene, ethylbenzene and xylenes (this group is commonly referred to as ''BTEX'') and n-hexane. These pollutants and any other HAP included in the VOC emissions controlled under the NSPS, including requirements for additional sources being proposed in this action, are controlled to the same degree. The co-benefit HAP reductions for the measures being proposed are discussed in the Regulatory Impact Analysis (RIA) and in the Background Technical Support Document (TSD) which are included in the public docket for this action.

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025 when using a 7 percent discount rate. When estimated revenues from additional natural gas are included, the annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025, assuming a wellhead natural gas price of $4/thousand cubic feet (Mcf). These compliance cost estimates include revenues from recovered natural gas as the EPA estimates that about 8 billion cubic feet in 2020 and 16 to 19 billion cubic feet in 2025 of natural gas will be recovered by implementing the NSPS.

Considering all the costs and benefits of this proposed rule, including the resources from recovered natural gas that would otherwise be vented, this rule results in a net benefit. The quantified net benefits (the difference between monetized benefits and compliance costs) are estimated to be $35 to $42 million in 2020 using a 3 percent discount rate (model average) for climate benefits.[4] The quantified net benefits are estimated to be $120 to $150 million in 2025 using a 3 percent discount rate (model average) for climate benefits. All dollar amounts are in 2012 dollars.

[3] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this summary, we present the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA.

[4] Figures may not sum due to rounding.

The EPA was unable to monetize all of the benefits anticipated to result from this proposal. The only benefits monetized for this rule are methane-related climate benefits. However, there would be additional benefits from reducing VOC and HAP emissions, as well as additional benefits from reducing methane emissions because methane is a precursor to global background concentrations of ozone. A detailed discussion of these unquantified benefits are discussed in section XI of this document as well as in the RIA available in the docket.

III. General Information

A. Does this reconsideration notice apply to me?

Categories and entities potentially affected by today's notice include:

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS ACTION

Category	NAICS code [1]	Examples of regulated entities
Industry	211111	Crude Petroleum and Natural Gas Extraction.
	211112	Natural Gas Liquid Extraction.
	221210	Natural Gas Distribution.
	486110	Pipeline Distribution of Crude Oil.
	486210	Pipeline Transportation of Natural Gas.
Federal government		Not affected.
State/local/tribal government		Not affected.

[1] North American Industry Classification System.

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. 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. What should I consider as I prepare my comments to the EPA?

We seek comment only on the aspects of the new source performance standards for the oil and natural gas source category for the equipment, processes and activities specifically identified in this document. We are not opening for reconsideration any other provisions of the new source performance standards at this time.

Do not submit information containing CBI to the EPA through www.regulations.gov or email. Send or deliver information identified as CBI only to the following address: OAQPS Document Control Officer (C404–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711, Attention: Docket ID Number EPA–HQ–OAR–2010–0505. Clearly mark the part or all of the information that you claim to be CBI. For CBI information in a disk or CD–ROM that you mail to the EPA, mark the outside of the disk or CD–ROM as CBI and then identify electronically within the disk or CD–ROM the specific information that is claimed as CBI. In addition to one complete version of the comment that includes information claimed as CBI, a copy of the comment that does not contain the information claimed as CBI must be submitted for inclusion in the public docket. Information so marked will not be disclosed except in accordance with procedures set forth in 40 CFR part 2.

C. How do I obtain a copy of this document and other related information?

In addition to being available in the docket, electronic copies of these proposed rules will be available on the Worldwide Web through the Technology Transfer Network (TTN). Following signature, a copy of each proposed rule will be posted on the TTN's policy and guidance page for newly proposed or promulgated rules at the following address: *http://www.epa.gov/ttn/oarpg/*. The TTN provides information and technology exchange in various areas of air pollution control.

IV. Background

A. Statutory Background

Section 111 of the CAA requires the EPA Administrator to list categories of stationary sources that, in his or her judgment, cause or contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. The EPA must then issue ''standards of performance'' for new sources in such source categories. The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, and identify within each source category the facilities for which standards of performance would be established.

CAA Section 111(a)(1) defines ''a standard of performance'' as ''a standard for emissions of air pollutants which reflects the degree of emission limitation achievable through the application of the best system of emission reduction which (taking into account the cost of achieving such reduction and any nonair quality health and environmental impact and energy requirement) the Administrator determines has been adequately demonstrated.'' This definition makes clear that the standard of performance must be based on controls that constitute ''the best system of emission reduction . . . adequately demonstrated''. The standard that the EPA develops, based on the BSER, is commonly a numerical emissions limit, expressed as a performance level (*e.g.*, a rate-based standard). Generally, the EPA does not prescribe a particular technological system that must be used to comply with a standard of performance. Rather, sources generally can select any measure or combination of measures that will achieve the emissions level of the standard.

Standards of performance under section 111 are issued for new, modified and reconstructed stationary sources. These standards are referred to as ''new source performance standards.'' The EPA has the authority to define the source categories, determine the pollutants for which standards should be developed, identify the facilities within each source category to be covered and set the emission level of the standards.

CAA section 111(b)(1)(B) requires the EPA to ''at least every 8 years review and, if appropriate, revise'' performance standards unless the ''Administrator determines that such review is not appropriate in light of readily available information on the efficacy'' of the standard. When conducting a review of an existing performance standard, the EPA has discretion to revise that standard to add emission limits for pollutants or emission sources not currently regulated for that source category.

B. What are the regulatory history and litigation background regarding performance standards for the oil and natural gas sector?

In 1979, the EPA published a list of source categories, including ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under section 111(b) of the CAA. See *Priority List and Additions to the List of Categories of Stationary Sources*, 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to section 111(b)(1)(A), contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR at 49223; see also, 49 FR 2636, 2637. In 1979, the EPA listed crude oil and natural gas production on its priority list of source categories for promulgation of NSPS (44 FR 49222, August 21, 1979).

On June 24, 1985 (50 FR 26122), the EPA promulgated an NSPS for the source category that addressed VOC emissions from leaking components at onshore natural gas processing plants (40 CFR part 60, subpart KKK). On October 1, 1985 (50 FR 40158), a second NSPS was promulgated for the source category that regulates sulfur dioxide (SO_2) emissions from natural gas processing plants (40 CFR part 60, subpart LLL). In 2012, pursuant to its authority under section 111(b)(1)(B) to review and, if appropriate, revise NSPS, the EPA published the final rule, ''Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution'' (40 CFR part 60, subpart OOOO)(''2012 NSPS''). The 2012 NSPS updated the VOC standards for equipment leaks at onshore natural gas processing plants. In addition, it established VOC standards for several oil and natural gas-related operations not covered by subpart KKK, including gas well completions, centrifugal and reciprocating compressors, natural gas-operated pneumatic controllers and storage vessels. In 2013 and 2014, the EPA made certain amendments to the 2012 NSPS in order to improve implementation of the standards (78 FR 58416 and 79 FR 79018). The 2013 amendments focused on storage vessel implementation issues; the 2014 amendments provided clarification of well completion provisions which became fully effective on January 1, 2015. The EPA received petitions for both judicial review and administrative reconsiderations for the 2012 NSPS as well as the subsequent amendments in 2013 and 2014. The litigations are stayed pending the EPA's reconsideration process.

In this rulemaking, the EPA is granting reconsideration of a number of issues raised in the administrative reconsideration petitions and, where appropriate, is proposing amendments to address such issues. These issues, which mostly address implementation, are as follows: storage vessel control device monitoring and testing provisions, initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device, recordkeeping requirements of § 60.5420(c) for repair logs for control devices failing a visible emissions test, clarification of the due date for the initial annual report under the 2012 NSPS, emergency flare exemption from routine compliance tests, LDAR for open-ended valves or lines, compliance period for LDAR for newly affected process units, exemption to notification requirement for reconstruction of most types of facilities, and disposal of carbon from control devices.

C. Events Leading to Today's Action

Several factors have led to today's proposed action. First, the EPA in 2009 found that six well-mixed GHGs—carbon dioxide, methane, nitrous oxide, hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride—endanger both the public health and the public welfare of current and future generations by causing or contributing to climate change. Oil and gas operations are significant emitters of methane. According to Greenhouse Gas Reporting Program (GHGRP) data, oil and gas operations are the second largest emitter of GHGs in the U.S. (when considering both methane emissions and combustion-related GHG emissions at oil and gas facilities), second only than fossil-fueled electricity generation. This endangerment finding is described in more detail in section VI.

Second, on August 16, 2012, the EPA published the 2012 NSPS (77 FR 49490). The 2012 NSPS included VOC standards for a number of emission sources in the oil and natural gas source category. Based on information available at the time, the EPA also evaluated methane emissions and reductions during the 2012 NSPS rulemaking as a potential co-benefit from regulating VOC. Although information at the time indicated that methane emissions could be significant, the EPA did not take final action in the 2012 NSPS with respect to the regulation of methane; the EPA noted the impending collection of a large amount of GHG data for this industry through the GHGRP (40 CFR part 98) and expressed its intent to continue its evaluation of methane. As stated previously, the 2012 NSPS is the subject of a number of petitions for judicial review and administrative reconsideration. The litigation is currently stayed pending the EPA's reconsideration process. Regulation of methane is an issue raised in several of the administrative petitions for the EPA's reconsideration.

Third, in June 2013, President Obama issued his Climate Action Plan which, among other actions, directed the EPA and five other federal agencies to develop a comprehensive interagency strategy to reduce methane emissions. The plan recognized that methane emissions constitute a significant percentage of domestic GHG emissions, highlighted reductions in methane emissions since 1990, and outlined specific actions that could be taken to achieve additional progress. Specifically, the federal agencies were instructed to focus on ''assessing current emissions data, addressing data gaps, identifying technologies and best practices for reducing emissions and identifying existing authorities and incentive-based opportunities to reduce methane emissions.''

Fourth, as a follow-up to the 2013 Climate Action Plan, the Climate Action Plan: Strategy to Reduce Methane Emissions (the Methane Strategy) was released in March 2014. The focus on reducing methane emissions reflects the fact that methane is a potent GHG with a 100-year global warming potential (GWP) that is 28–36 times greater than that of carbon dioxide.[5] Methane has an atmospheric life of about 12 years, and because of its potency as a GHG and its atmospheric life, reducing methane emissions is an important step that can be taken to achieve a near-term beneficial impact in mitigating global climate change. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and to solicit input from independent experts. The papers were released in April 2014.

[5] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. Note that for purposes of inventories and reporting, GWP values from the 4th Assessment Report may be used.

They focused on technical issues, covering emissions and control technologies that reduce both VOC and methane, with particular focus on completions of hydraulically fractured oil wells, liquids unloading, leaks, pneumatic devices and compressors. The peer review process was completed on June 16, 2014. The EPA received 26 submissions of peer review comments on these papers, and more than 43,000 comments from the public. The comments received from the peer reviewers are available on EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in EPA's nonregulatory docket at *www.regulations.gov,* docket ID # EPA–HQ–OAR–2014–0557. The Methane Strategy also instructed the EPA to complete any new oil and natural gas regulations pertaining to the sources addressed in the white papers by the end of 2016.

Finally, following the Climate Action Plan and Methane Strategy, in January 2015, the Administration announced a new goal to cut methane emissions from the oil and gas sector (by 40–45 percent from 2012 levels by 2025) and steps to put the U.S. on a path to achieve this ambitious goal. These actions encompass both commonsense standards and cooperative engagement with states, tribes and industry. Building on prior actions by the Administration, and leadership in states and industry, the announcement laid out a plan for EPA to address, and if appropriate, propose and set commonsense standards for methane and ozone forming emissions from new and modified sources and issue Control Technique Guidelines (CTGs) to assist states in reducing ozone-forming pollutants from existing oil and gas systems in areas that do not meet the health-based standard for ozone.

Building on the 2012 NSPS, the EPA intends to encourage corporate-wide efforts to achieve emission reductions through transparent and verifiable voluntary action that would obviate the burden associated with NSPS applicability. Throughout this proposal, we solicit comment on specific approaches that could provide incentive for owners and operators to design and implement programs to reduce fugitive emissions at their facilities.

V. Why is the EPA Proposing to Establish Methane Standards in the Oil and Natural Gas NSPS?

In a petition for reconsideration of the 2012 NSPS, the petitioners urged that ''EPA must reconsider its failure adopt standards for the methane pollution released by the oil and gas sector.'' [6] Upon reconsidering the issue, and on the basis of the wealth of additional information now available to us, the EPA is proposing to establish methane standards for facilities throughout the oil and natural gas source category.

The EPA has discretion under CAA section 111(b) to determine which pollutants emitted from a listed source category warrant regulation.[7] In making such determination, we have generally considered a number of factors to help inform our decision (We discuss considerations specific to individual emission source types in section VIII as part of the BSER analyses and rationale for regulating the sources). These factors include the amount such pollutant is being emitted from the source category, the availability of technically feasible control options and the costs of such control options. As we previously explained, ''we have historically declined to propose standards for a pollutant where it is emitting (sic) in low amounts or where we determined that a [control analysis] would result in no control'' device being used. 75 FR 54970, 54997 (Sep. 9, 2010). Our consideration of these factors are provided below and in more detail in sections VI and VIII.

The oil and natural gas industry is one of the largest emitters of methane, a GHG with a global warming potential more than 25 times greater than that of carbon dioxide. During the 2012 oil and natural gas NSPS rulemaking, while we had considerable amount of data and understanding on VOC emissions from the oil and natural gas industry and the available control options, data on methane emissions were just emerging. In light of the rapid expansion of this industry and the growing concern with the associated emissions, the EPA proceeded to establish a number of VOC standards in the 2012 NSPS but indicated in that rulemaking an intent to revisit methane at a later date when additional information was available from the GHGRP. We have since received and evaluated such data, which confirm that the oil and natural gas industry is one of the largest emitters of methane. As discussed in section VI, the current methane emissions from this industry contribute substantially to nationwide GHG emissions. These emissions are expected to increase as a result of the rapid growth of this industry. While the VOC standards in the 2012 NSPS also reduce methane emissions, in light of the current and projected future methane emissions from the oil and natural gas industry, reducing methane emissions from this source category cannot be treated simply as an incidental benefit to VOC reduction; rather, it is something that should be directly addressed through standards for methane under section 111(b) based on direct evaluation of the extent and impact of methane emissions from this source category and the best system for their reduction. Such standards, which would be reviewed and, if appropriate, revised at least every eight years, would achieve meaningful methane reductions and, as such, would be an important step towards mitigating the impact of GHG emissions on climate change. In addition, while many of the currently regulated emission sources are equipment used throughout the oil and natural gas industry (*e.g.*, pneumatic controllers, compressors) and emit both VOC and methane, the current VOC standards apply only to a subset of these equipment based on VOC-only evaluation. However, as shown in section VIII, there are cost-effective controls that can simultaneously reduce both methane and VOC emissions from these equipment across the industry, which in some instances would not occur were we to focus solely on VOC reductions. Revising the NSPS to establish both methane and VOC standards for all such equipment across the industry would also promote consistency by providing the same regulatory regime for these equipment throughout the oil and natural gas source category, thereby facilitating implementation and enforcement.[8]

As mentioned above, we also we consider whether there are technically feasiable control options that can be applied nationally to sources to mitigate emissions of a pollutant and whether the costs of such controls are reasonable. As discussed in detail in section VIII, we have identified

[6] Sierra Club *et al.*, Petition for Reconsideration, In the Matter of: Final Rule Published at 77 FR 49490 (Aug. 16, 2012), titled ''Oil and Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews; Final Rule,'' Docket No. EPA–HQ–OAR–2010–0505, RIN 2060–AP76 (2012).

[7] See 42 U.S.C. § 7411(b)

[8] The EPA often revises standards even where the revision will not lead to any additional reductions of a pollutant because another standard regulates a different pollutant using the same control equipment. For example, in 2014, the EPA revised the Kraft Pulp Mill NSPS in Part 60 Subpart BB (published at 70 FR 18952 (April 4, 2014) to align the NSPS standards with the NESHAP standards for those sources in Part 63 Subpart S. Although no previously unregulated sources were added to the Kraft Pulp Mill NSPS, several emission limits were adjusted downward. The revised NSPS did not achieve additional reductions beyond those achieved by the NESHAP, but eased compliance burden for the sources.

technically feasible controls that can be applied nationally to reduce methane emissions and thus GHG emissions from the oil and natural gas source category. We consider whether the costs (*e.g.*, capital costs, operating costs) are reasonable considering the emission reductions achieved through application of the controls that would be required by the proposed rule. As discussed in detail in section VIII, for the oil and natural gas source category, the available controls for reducing methane emissions simultaneously control VOC emissions and vice versa. Accordingly, the available controls are the same for reducing methane and VOC from the individual oil and natural gas emission sources. For a detailed discussion on how we evaluated control costs and our cost analysis for individual emission sources, please see section VIII. As shown in that section, there are cost-effective controls for reducing methane emissions from the oil and natural gas source category.

Based on our consideration of the three factors, the EPA is proposing to revise the NSPS to regulate directly GHG emissions in addition to VOC emissions across the oil and natural gas source category. The proposed standards include adding methane standards to certain sources currently regulated for VOC, as well as methane and VOC standards for additional emission sources. Specifically,

- Well completions: We are proposing to revise the current NSPS to regulate both methane and VOC emissions from well completions of all hydraulically fractured wells (*i.e.*, gas wells and oil wells);
- Fugitive emissions: We are proposing standards to reduce methane and VOC emissions from fugitive emission components at well sites and compressor stations;
- Pneumatic pumps: We are proposing methane and VOC standards;
- Pneumatic controllers, centrifugal compressors, and reciprocating compressors (industry-wide, except for well site compressors, of which only a subset of those equipment are regulated currently): We are proposing to establish methane and VOC standards across the industry by adding methane standards to those currently subject to VOC standard and VOC and methane standards for all the others.
- Equipment leaks at natural gas processing plants: We are proposing to add methane standards.

For a detailed description of the proposed standards, please see section VII. For the BSER analyses that serve as the bases for the proposed standards, please see section VIII.

VI. The Oil and Natural Gas Source Category Listing Under CAA Section 111(b)(1)(A)

Section 111(b)(1)(A) of the CAA, which Congress enacted as part of the 1970 CAA Amendments, requires the EPA to promulgate a list of categories of stationary sources that the Administrator, in his or her judgment, finds ''causes, or contributes significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.'' In 1979, the EPA published a list of source categories, including ''crude oil and natural gas production,'' for which the EPA would promulgate standards of performance under section 111(b) of the CAA. *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222 (August 21, 1979) (''1979 Priority List''). That list included, in the order of priority for promulgating standards, source categories that the EPA Administrator had determined, pursuant to section 111(b)(1)(A), to contribute significantly to air pollution that may reasonably be anticipated to endanger public health or welfare. See 44 FR 49222; see also, 49 FR 2636, 2637.

As mentioned above, one of the source categories listed in that 1979 rulemaking related to the oil and natural gas industry. The EPA interprets the listing that resulted from that rulemaking as generally covering the oil and natural gas industry. Specifically, with respect to the natural gas industry, it includes production, processing, transmission, and storage. The EPA believes that the intent of the 1979 listing was to broadly cover the natural gas industry.[9] This intent was evident in the EPA's analysis at the time of listing.[10] For example, the priority list analysis indicated that the EPA evaluated emissions beyond the natural gas production segment to include emissions from natural gas processing plants. The analysis also showed that the EPA evaluated equipment, such as stationary pipeline compressor engines, that are used in various segments of the natural gas industry. The EPA's interpretation of the 1979 listing is further supported by the Agency's pronouncements during the NSPS rulemaking that followed the listing. Specifically, in its description of this listed source category in the 1984 preamble to the proposed NSPS for equipment leaks at natural gas processing plants, the EPA described the major emission points of this source category to include process, storage and equipment leaks; these emissions can be found throughout the various segments of the natural gas industry. 49 FR at 2637. There are also good reasons for treating various segments of the natural gas industry as one source category. Operations at production, processing, transmission and storage facilities are a sequence of functions that are interrelated and necessary for getting the recovered gas ready for distribution.[11] Because they are interrelated, segments that follow others are faced with increases in throughput caused by growth in throughput of the segments preceding (*i.e.,* feeding) them. For example, the relatively recent substantial increases in natural gas production brought about by hydraulic fracturing and horizontal drilling result in increases in the amount of natural gas needing to be processed and moved to market or stored. These increases in production and throughput can cause increases in emissions across the entire natural gas industry. We also note that some equipment (*e.g.,* storage vessels, compressors) are used across the oil and natural gas industry, which further supports considering the industry as one source category. For the reasons stated above, the EPA interprets the 1979 listing broadly to include the various segments of the natural gas industry (production, processing, transmission, and storage).

Since the 1979 listing, EPA has promulgated performance standards to regulate SO_2 emissions from natural gas processing and VOC emissions from the oil and natural gas industry. In this action, the EPA is proposing to further regulate VOC emissions as well as proposing performance standards for methane emissions from this industry. With respect to the latter, the EPA identifies the air pollutant that it proposes to regulate as the pollutant GHGs (which consist of the six well-mixed gases, consistent with other actions the EPA has taken under the

[9] The process of producing natural gas for distribution involves operations in the various segments of the natural gas industry described above. In contrast, oil production involves drilling/extracting oil, which is immediately followed by distribution offsite to be made into different products.

[10] See *Standards of Performance for New Stationary Sources,* 43 FR 38872, August 31, 1978, and *Priority List and Additions to the List of Categories of Stationary Sources,* 44 FR 49222, August 21, 1979.

[11] The crude oil production segment of the source category, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline, is more limited in scope than the segments of the natural gas value chain included in the source category. However, increases in production at the well and/or increases in the number of wells coming on line, in turn increase throughput and resultant emissions, similarly to the natural gas segments in the source category.

CAA), although only methane will be reduced directly by the proposed standards.

As mentioned above, in the 1979 category listing, section 111(b)(1)(A) does not require another determination as a prerequisite for regulating a particular pollutant. Rather, once the EPA has determined that the source category causes, or contributes significantly to, air pollution that may reasonably be anticipated to endanger public health or welfare, and has listed the source category on that basis, the EPA interprets section 111(b)(1)(A) to provide authority to establish a standard for performance for any pollutant emitted by that source category as long as the EPA has a rational basis for setting a standard for the pollutant.[12] The EPA believes that the information included below in this section provides a rational basis for the methane standards it is proposing in this action.

First, because the EPA is not listing a new source category in this rule, the EPA is not required to make a new endangerment finding with regard to oil and natural gas source category in order to establish standards of performance for the methane from those sources. Under the plain language of CAA section 111(b)(1)(A), an endangerment finding is required only to list a source category. Further, though the endangerment finding is based on determinations as to the health or welfare impacts of the pollution to which the source category's pollutants contribute, and as to the significance of the amount of such contribution, the statute is clear that the endangerment finding is made with respect to the source category; section 111(b)(1)(A) does not provide that an endangerment finding is made as to specific pollutants. This contrasts with other CAA provisions that do require the EPA to make endangerment findings for each particular pollutant that the EPA regulates under those provisions. E.g., CAA sections 202(a)(1), 211(c)(1), 231(a)(2)(A). See *American Electric Power* v. *Connecticut,* 131 S. Ct. 2527, 2539 (2011) (''the Clean Air Act directs EPA to establish emissions standards for categories of stationary sources that, 'in [the Administrator's] judgment,' 'caus[e], or contribut[e] significantly to, air pollution which may reasonably be anticipated to endanger public health or welfare.' § 7411(b)(1)(A).'') (emphasis added).

Second, once a source category is listed, the CAA does not specify what pollutants should be the subject of standards from that source category. The statute, in section 111(b)(1)(B), simply directs the EPA to propose and then promulgate regulations ''establishing Federal standards of performance for new sources within such category.'' In the absence of specific direction or enumerated criteria in the statute concerning what pollutants from a given source category should be the subject of standard, it is appropriate for EPA to exercise its authority to adopt a reasonable interpretation of this provision. *Chevron U.S.A. Inc.* v. *NRDC,* 467 U.S. 837, 843–44 (1984).

The EPA has previously interpreted this provision as granting it the discretion to determine which pollutants should be regulated. See Standards of Performance for Petroleum Refineries, 73 FR 35838, 35858 (col. 3) (June 24, 2008) (concluding the statute provides ''the Administrator with significant flexibility in determining which pollutants are appropriate for regulation under section 111(b)(1)(B)'' and citing cases). Further, in directing the Administrator to propose and promulgate regulations under section 111(b)(1)(B), Congress provided that the Administrator should take comment and then finalize the standards with such modifications ''as he deems appropriate.'' The DC Circuit has considered similar statutory phrasing from CAA section 231(a)(3) and concluded that ''[t]his delegation of authority is both explicit and extraordinarily broad.'' *National Assoc. of Clean Air Agencies* v. *EPA,* 489 F.3d 1221, 1229 (D.C. Cir. 2007).

In exercising its discretion with respect to which pollutants are appropriate for regulation under section 111(b)(1)(B), the EPA has in the past provided a rational basis for its decisions. See *National Lime Assoc.* v. *EPA,* 627 F.2d 416, 426 & n.27 (D.C. Cir. 1980) (court discussed, but did not review, the EPA's reasons for not promulgating standards for NO_X, SO_2 and CO from lime plants''); Standards of Performance for Petroleum Refineries, 73 FR at 35859–60 (June 24, 2008) (providing reasons why the EPA was not promulgating GHG standards for petroleum refineries as part of that rule). Though these previous examples involved the EPA providing a rational basis for not setting standards for a given pollutant, a similar approach is appropriate where the EPA determines that it should set a standard for an additional pollutant for a source category that was previously listed and regulated for other pollutants.

While the EPA believes that the 1979 listing of this source category provides sufficient authority for this action, to the extent that there is any ambiguity in the prior listing, the information provided here should be considered to constitute the requisite conclusions related to the category listing. Were EPA to formally seek to revise the category listing to broadly include the oil and natural gas industry (i.e., production, processing, transmission, and storage)[13], we believe this information discussed here fully suffices to support it as a source category that, in the Administrator's judgment, contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Furthermore, for the reason stated below, EPA's previous determination under section 111(b)(1)(A) is sufficient to support the proposed revision to the category listing as well as the proposed standards in this action. During the 1979 listing, EPA had determined that, at least a part of the oil and natural gas industry contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. Such health and welfare impacts could only increase when considering the broader industry (assuming it had not already been considered in the 1979 listing). To further support the conclusion related to this category listing, EPA has included below in this section information and analyses regarding the public health and welfare impacts from GHG, VOC and SO_2 emissions, three of the primary pollutants emitted from the oil and natural gas industry, and the estimated emissions of these pollutants from the oil and natural gas source category. It is evident from this information and analyses that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health or welfare.

Provided below are the supporting information and analyses. Specifically, section VI.A describes the public health and welfare impacts from GHG, VOC and SO_2. Section VI.B analyzes the emission contribution of these three pollutants by the oil and natural gas industry.

A. Impacts of GHG, VOC and SO_2 Emissions on Public Health and Welfare

The oil and natural gas industry emits a wide range of pollutants, including GHGs (such as methane and CO_2), VOC, SO_2, NO_X, H_2S, CS_2 and COS. See 49 FR 2636, at 2637 (Jan 20, 1984). Although all of these pollutants have significant impacts on public health and welfare, an analysis of every one of these

[12] See additional discussion at 79 FR 1430, 1452 (Jan 8, 2014).

[13] For the oil industry, the listing includes production, as explained above in footnote 10.

pollutants is not necessary for the Administrator to make a determination under section 111(b)(1)(A); as shown below, the EPA's analysis of GHG, VOC, and SO_2, three of the primary emissions from the oil and natural gas source category, alone are sufficient for the Administrator to determine under section 111(b)(1)(A) that the oil and natural gas source category contributes significantly to air pollution which may reasonably be anticipated to endanger public health and welfare.[14]

1. Climate Change Impacts from GHG Emissions

In 2009, based on a large body of robust and compelling scientific evidence, the EPA Administrator issued the Endangerment Finding under CAA section 202(a)(1).[15] In the Endangerment Finding, the Administrator found that the current, elevated concentrations of GHGs in the atmosphere—already at levels unprecedented in human history—may reasonably be anticipated to endanger public health and welfare of current and future generations in the United States. We summarize these adverse effects on public health and welfare briefly here.

a. Public Health Impacts Detailed in the 2009 Endangerment Finding

Climate change caused by human emissions of GHGs threatens the health of Americans in multiple ways. By raising average temperatures, climate change increases the likelihood of heat waves, which are associated with increased deaths and illnesses. While climate change also increases the likelihood of reductions in cold-related mortality, evidence indicates that the increases in heat mortality will be larger than the decreases in cold mortality in the United States. Compared to a future without climate change, climate change is expected to increase ozone pollution over broad areas of the U.S., especially on the highest ozone days and in the largest metropolitan areas with the worst ozone problems, and thereby increase the risk of morbidity and mortality. Climate change is also expected to cause more intense hurricanes and more frequent and intense storms and heavy precipitation, with impacts on other areas of public health, such as the potential for increased deaths, injuries, infectious and waterborne diseases, and stress-related disorders. Children, the elderly, and the poor are among the most vulnerable to these climate-related health effects.

b. Public Welfare Impacts Detailed in the 2009 Endangerment Finding

Climate change impacts touch nearly every aspect of public welfare. Among the multiple threats caused by human emissions of GHGs, climate changes are expected to place large areas of the country at serious risk of reduced water supplies, increased water pollution, and increased occurrence of extreme events such as floods and droughts. Coastal areas are expected to face a multitude of increased risks, particularly from rising sea level and increases in the severity of storms. These communities face storm and flooding damage to property, or even loss of land due to inundation, erosion, wetland submergence and habitat loss.

Impacts of climate change on public welfare also include threats to social and ecosystem services. Climate change is expected to result in an increase in peak electricity demand, Extreme weather from climate change threatens energy, transportation, and water resource infrastructure. Climate change may also exacerbate ongoing environmental pressures in certain settlements, particularly in Alaskan indigenous communities, and is very likely to fundamentally rearrange U.S. ecosystems over the 21st century. Though some benefits may balance adverse effects on agriculture and forestry in the next few decades, the body of evidence points towards increasing risks of net adverse impacts on U.S. food production, agriculture and forest productivity as temperature continues to rise. These impacts are global and may exacerbate problems outside the U.S. that raise humanitarian, trade, and national security issues for the U.S.

c. New Scientific Assessments and Observations

Since the administrative record concerning the Endangerment Finding closed following the EPA's 2010 Reconsideration Denial, the climate has continued to change, with new records being set for a number of climate indicators such as global average surface temperatures, Arctic sea ice retreat, CO_2 concentrations, and sea level rise. Additionally, a number of major scientific assessments have been released that improve understanding of the climate system and strengthen the case that GHGs endanger public health and welfare both for current and future generations. These assessments, from the Intergovernmental Panel on Climate Change (IPCC), the U.S. Global Change Research Program (USGCRP), and the National Research Council of the National Academies (NRC), include: IPCC's 2012 *Special Report on Managing the Risks of Extreme Events and Disasters to Advance Climate Change Adaptation* (SREX) and the 2013–2014 Fifth Assessment Report (AR5), USGCRP's 2014 National Climate Assessment, Climate Change Impacts in the United States (NCA3), and the NRC's 2010 *Ocean Acidification: A National Strategy to Meet the Challenges of a Changing Ocean* (Ocean Acidification), 2011 *Report on Climate Stabilization Targets: Emissions, Concentrations, and Impacts over Decades to Millennia* (Climate Stabilization Targets), 2011 *National Security Implications for U.S. Naval Forces* (National Security Implications), 2011 *Understanding Earth's Deep Past: Lessons for Our Climate Future* (Understanding Earth's Deep Past), 2012 *Sea Level Rise for the Coasts of California, Oregon, and Washington: Past, Present, and Future,* 2012 *Climate and Social Stress: Implications for Security Analysis* (Climate and Social Stress), and 2013 *Abrupt Impacts of Climate Change* (Abrupt Impacts) assessments.

The EPA has carefully reviewed these recent assessments in keeping with the same approach outlined in Section VIII.A. of the 2009 Endangerment Finding, which was to rely primarily upon the major assessments by the USGCRP, IPCC, and the NRC to provide the technical and scientific information to inform the Administrator's judgment regarding the question of whether GHGs endanger public health and welfare. These assessments addressed the scientific issues that the EPA was required to examine were comprehensive in their coverage of the GHG and climate change issues, and underwent rigorous and exacting peer review by the expert community, as well as rigorous levels of U.S. government review.

The findings of the recent scientific assessments confirm and strengthen the conclusion that GHGs endanger public health, now and in the future. The NCA3 indicates that human health in the United States will be impacted by ''increased extreme weather events, wildfire, decreased air quality, threats to mental health, and illnesses transmitted by food, water, and disease-carriers such as mosquitoes and ticks.'' The most recent assessments now have greater

[14] We note that EPA's focus on GHG (in particular methane), VOC and SO_2 in these analyses, does not in any way limit the EPA's authority to promulgate standards that would apply to other pollutants emitted from the oil and natural gas source category, if the EPA determines that such action is appropriate.

[15] ''Endangerment and Cause or Contribute Findings for Greenhouse Gases Under Section 202(a) of the Clean Air Act,'' 74 FR 66496 (Dec. 15, 2009) (''Endangerment Finding'').

confidence that climate change will influence production of pollen that exacerbates asthma and other allergic respiratory diseases such as allergic rhinitis, as well as effects on conjunctivitis and dermatitis. Both the NCA3 and the IPCC AR5 found that increasing temperature has lengthened the allergenic pollen season for ragweed, and that increased CO_2 by itself can elevate production of plant-based allergens.

The NCA3 also finds that climate change, in addition to chronic stresses such as extreme poverty, is negatively affecting indigenous peoples' health in the United States through impacts such as reduced access to traditional foods, decreased water quality, and increasing exposure to health and safety hazards. The IPCC AR5 finds that climate change-induced warming in the Arctic and resultant changes in environment (*e.g.,* permafrost thaw, effects on traditional food sources) have significant impacts, observed now and projected, on the health and well-being of Arctic residents, especially indigenous peoples. Small, remote, predominantly-indigenous communities are especially vulnerable given their ''strong dependence on the environment for food, culture, and way of life; their political and economic marginalization; existing social, health, and poverty disparities; as well as their frequent close proximity to exposed locations along ocean, lake, or river shorelines.'' [16] In addition, increasing temperatures and loss of Arctic sea ice increases the risk of drowning for those engaged in traditional hunting and fishing.

The NCA3 concludes that children's unique physiology and developing bodies contribute to making them particularly vulnerable to climate change. Impacts on children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. The IPCC AR5 indicates that children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. The IPCC finds that additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

Both the NCA3 and IPCC AR5 conclude that climate change will increase health risks facing the elderly. Older people are at much higher risk of mortality during extreme heat events. Pre-existing health conditions also make older adults susceptible to cardiac and respiratory impacts of air pollution and to more severe consequences from infectious and waterborne diseases. Limited mobility among older adults can also increase health risks associated with extreme weather and floods.

The new assessments also confirm and strengthen the conclusion that GHGs endanger public welfare, and emphasize the urgency of reducing GHG emissions due to their projections that show GHG concentrations climbing to ever-increasing levels in the absence of mitigation. The NRC assessment Understanding Earth's Deep Past projected that, without a reduction in emissions, CO_2 concentrations by the end of the century would increase to levels that the Earth has not experienced for more than 30 million years.[17] In fact, that assessment stated that ''the magnitude and rate of the present GHG increase place the climate system in what could be one of the most severe increases in radiative forcing of the global climate system in Earth history.'' [18] Because of these unprecedented changes, several assessments state that we may be approaching critical, poorly understood thresholds: As stated in the NRC assessment Understanding Earth's Deep Past, ''As Earth continues to warm, it may be approaching a critical climate threshold beyond which rapid and potentially permanent—at least on a human timescale—changes not anticipated by climate models tuned to modern conditions may occur.'' The NRC Abrupt Impacts report analyzed abrupt climate change in the physical climate system and abrupt impacts of ongoing changes that, when thresholds are crossed, can cause abrupt impacts for society and ecosystems. The report considered destabilization of the West Antarctic Ice Sheet (which could cause 3–4 m of potential sea level rise) as an abrupt climate impact with unknown but probably low probability of occurring this century. The report categorized a decrease in ocean oxygen content (with attendant threats to aerobic marine life); increase in intensity, frequency, and duration of heat waves; and increase in frequency and intensity of extreme precipitation events (droughts, floods, hurricanes, and major storms) as climate impacts with moderate risk of an abrupt change within this century. The NRC *Abrupt Impacts* report also analyzed the threat of rapid state changes in ecosystems and species extinctions as examples of an irreversible impact that is expected to be exacerbated by climate change. Species at most risk include those whose migration potential is limited, whether because they live on mountaintops or fragmented habitats with barriers to movement, or because climatic conditions are changing more rapidly than the species can move or adapt. While the NRC determined that it is not presently possible to place exact probabilities on the added contribution of climate change to extinction, they did find that there was substantial risk that impacts from climate change could, within a few decades, drop the populations in many species below sustainable levels thereby committing the species to extinction. Species within tropical and subtropical rainforests such as the Amazon and species living in coral reef ecosystems were identified by the NRC as being particularly vulnerable to extinction over the next 30 to 80 years, as were species in high latitude and high elevation regions. Moreover, due to the time lags inherent in the Earth's climate, the NRC Climate Stabilization Targets assessment notes that the full warming from increased GHG concentrations will not be fully realized for several centuries, underscoring that emission activities today carry with them climate commitments far into the future.

Future temperature changes will depend on what emission path the world follows. In its high emission scenario, the IPCC AR5 projects that global temperatures by the end of the century will likely be 2.6 °C to 4.8 °C (4.7 to 8.6 °F) warmer than today. Temperatures on land and in northern latitudes will likely warm even faster than the global average. However, according to the NCA3, significant reductions in emissions would lead to noticeably less future warming beyond mid-century, and therefore less impact to public health and welfare.

While rainfall may only see small globally and annually averaged changes, there are expected to be substantial shifts in where and when that precipitation falls. According to the NCA3, regions closer to the poles will see more precipitation, while the dry subtropics are expected to expand (colloquially, this has been summarized

[16] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part B: Regional Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Barros, V.R., C.B. Field, D.J. Dokken, M.D. Mastrandrea, K.J. Mach, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, Cambridge, p. 1581.

[17] National Research Council, Understanding Earth's Deep Past, p. 1.

[18] *Id.*, p. 138.

as wet areas getting wetter and dry regions getting drier). In particular, the NCA3 notes that the western U.S., and especially the Southwest, is expected to become drier. This projection is consistent with the recent observed drought trend in the West. At the time of publication of the NCA, even before the last 2 years of extreme drought in California, tree ring data were already indicating that the region might be experiencing its driest period in 800 years. Similarly, the NCA3 projects that heavy downpours are expected to increase in many regions, with precipitation events in general becoming less frequent but more intense. This trend has already been observed in regions such as the Midwest, Northeast, and upper Great Plains. Meanwhile, the NRC Climate Stabilization Targets assessment found that the area burned by wildfire is expected to grow by 2 to 4 times for 1 °C (1.8 °F) of warming. For 3 °C of warming, the assessment found that 9 out of 10 summers would be warmer than all but the 5 percent of warmest summers today, leading to increased frequency, duration, and intensity of heat waves. Extrapolations by the NCA also indicate that Arctic sea ice in summer may essentially disappear by mid-century. Retreating snow and ice, and emissions of carbon dioxide and methane released from thawing permafrost, will also amplify future warming.

Since the 2009 Endangerment Finding, the USGCRP NCA3, and multiple NRC assessments have projected future rates of sea level rise that are 40 percent larger to more than twice as large as the previous estimates from the 2007 IPCC 4th Assessment Report due in part to improved understanding of the future rate of melt of the Antarctic and Greenland ice sheets. The NRC Sea Level Rise assessment projects a global sea level rise of 0.5 to 1.4 meters (1.6 to 4.6 feet) by 2100, the NRC National Security Implications assessment suggests that ‘‘the Department of the Navy should expect roughly 0.4 to 2 meters (1.3 to 6.6 feet) global average sea-level rise by 2100,’’ [19] and the NRC Climate Stabilization Targets assessment states that an increase of 3 °C will lead to a sea level rise of 0.5 to 1 meter (1.6 to 3.3 feet) by 2100. These assessments continue to recognize that there is uncertainty inherent in accounting for ice sheet processes. Additionally, local sea level rise can differ from the global total depending on various factors: The east coast of the U.S. in particular is expected to see higher rates of sea level rise than the global average. For comparison, the NCA3 states that ‘‘five million Americans and hundreds of billions of dollars of property are located in areas that are less than four feet above the local high-tide level,’’ and the NCA3 finds that ‘‘[c]oastal infrastructure, including roads, rail lines, energy infrastructure, airports, port facilities, and military bases, are increasingly at risk from sea level rise and damaging storm surges.’’ [20] Also, because of the inertia of the oceans, sea level rise will continue for centuries after GHG concentrations have stabilized (though more slowly than it would have otherwise). Additionally, there is a threshold temperature above which the Greenland ice sheet will be committed to inevitable melting: According to the NCA, some recent research has suggested that even present day carbon dioxide levels could be sufficient to exceed that threshold.

In general, climate change impacts are expected to be unevenly distributed across different regions of the United States and have a greater impact on certain populations, such as indigenous peoples and the poor. The NCA3 finds climate change impacts such as the rapid pace of temperature rise, coastal erosion and inundation related to sea level rise and storms, ice and snow melt, and permafrost thaw are affecting indigenous people in the United States. Particularly in Alaska, critical infrastructure and traditional livelihoods are threatened by climate change and, ‘‘[i]n parts of Alaska, Louisiana, the Pacific Islands, and other coastal locations, climate change impacts (through erosion and inundation) are so severe that some communities are already relocating from historical homelands to which their traditions and cultural identities are tied.’’ [21] The IPCC AR5 notes, ‘‘Climate-related hazards exacerbate other stressors, often with negative outcomes for livelihoods, especially for people living in poverty (high confidence). Climate-related hazards affect poor people's lives directly through impacts on livelihoods, reductions in crop yields, or destruction of homes and indirectly through, for example, increased food prices and food insecurity.’’ [22]

Events outside the United States, as also pointed out in the 2009 Endangerment Finding, will also have relevant consequences. The NRC Climate and Social Stress assessment concluded that it is prudent to expect that some climate events ‘‘will produce consequences that exceed the capacity of the affected societies or global systems to manage and that have global security implications serious enough to compel international response.’’ The NRC National Security Implications assessment recommends preparing for increased needs for humanitarian aid; responding to the effects of climate change in geopolitical hotspots, including possible mass migrations; and addressing changing security needs in the Arctic as sea ice retreats.

In addition to future impacts, the NCA3 emphasizes that climate change driven by human emissions of GHGs is already happening now and it is happening in the United States. According to the IPCC AR5 and the NCA3, there are a number of climate-related changes that have been observed recently, and these changes are projected to accelerate in the future. The planet warmed about 0.85 °C (1.5 °F) from 1880 to 2012. It is extremely likely (>95% probability) that human influence was the dominant cause of the observed warming since the mid-20th century, and likely (>66% probability) that human influence has more than doubled the probability of occurrence of heat waves in some locations. In the Northern Hemisphere, the last 30 years were likely the warmest 30 year period of the last 1400 years. U.S. average temperatures have similarly increased by 1.3 to 1.9 degrees F since 1895, with most of that increase occurring since 1970. Global sea levels rose 0.19 m (7.5 inches) from 1901 to 2010. Contributing to this rise was the warming of the oceans and melting of land ice. It is likely that 275 gigatons per year of ice melted from land glaciers (not including ice sheets) since 1993, and that the rate of loss of ice from the Greenland and Antarctic ice sheets increased substantially in recent years, to 215 gigatons per year and 147 gigatons per year respectively since 2002. For

[19] NRC, 2011: *National Security Implications of Climate Change for U.S. Naval Forces.* The National Academies Press, p. 28.

[20] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 9.

[21] Melillo, Jerry M., Terese (T.C.) Richmond, and Gary W. Yohe, Eds., 2014: *Climate Change Impacts in the United States: The Third National Climate Assessment.* U.S. Global Change Research Program, p. 17.

[22] IPCC, 2014: *Climate Change 2014: Impacts, Adaptation, and Vulnerability. Part A: Global and Sectoral Aspects.* Contribution of Working Group II to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Field, C.B., V.R. Barros, D.J. Dokken, K.J. Mach, M.D. Mastrandrea, T.E. Bilir, M. Chatterjee, K.L. Ebi, Y.O. Estrada, R.C. Genova, B. Girma, E.S. Kissel, A.N. Levy, S. MacCracken, P.R. Mastrandrea, and L.L. White (eds.)]. Cambridge University Press, p. 796.

context, 360 gigatons of ice melt is sufficient to cause global sea levels to rise 1 millimeter (mm). Annual mean Arctic sea ice has been declining at 3.5 to 4.1 percent per decade, and Northern Hemisphere snow cover extent has decreased at about 1.6 percent per decade for March and 11.7 percent per decade for June. Permafrost temperatures have increased in most regions since the 1980s, by up to 3 °C (5.4 °F) in parts of Northern Alaska. Winter storm frequency and intensity have both increased in the Northern Hemisphere. The NCA3 states that the increases in the severity or frequency of some types of extreme weather and climate events in recent decades can affect energy production and delivery, causing supply disruptions, and compromise other essential infrastructure such as water and transportation systems.

In addition to the changes documented in the assessment literature, there have been other climate milestones of note. According to the IPCC, methane concentrations in 2011 were about 1803 parts per billion, 150 percent higher than concentrations were in 1750. After a few years of nearly stable concentrations from 1999 to 2006, methane concentrations have resumed increasing at about 5 parts per billion per year. Concentrations today are likely higher than they have been for at least the past 800,000 years. Arctic sea ice has continued to decline, with September of 2012 marking a new record low in terms of Arctic sea ice extent, 40 percent below the 1979–2000 median. Sea level has continued to rise at a rate of 3.2 mm per year (1.3 inches/decade) since satellite observations started in 1993, more than twice the average rate of rise in the 20th century prior to 1993.[23] And 2014 was the warmest year globally in the modern global surface temperature record, going back to 1880; this now means 19 of the 20 warmest years have occurred in the past 20 years, and except for 1998, the ten warmest years on record have occurred since 2002.[24] The first months of 2015 have also been some of the warmest on record.

These assessments and observed changes make it clear that reducing emissions of GHGs across the globe is necessary in order to avoid the worst impacts of climate change, and underscore the urgency of reducing emissions now. The NRC Committee on America's Climate Choices listed a number of reasons ''why it is imprudent to delay actions that at least begin the process of substantially reducing emissions.'' [25] For example:

- The faster emissions are reduced, the lower the risks posed by climate change. Delays in reducing emissions could commit the planet to a wide range of adverse impacts, especially if the sensitivity of the climate to GHGs is on the higher end of the estimated range.
- Waiting for unacceptable impacts to occur before taking action is imprudent because the effects of GHG emissions do not fully manifest themselves for decades and, once manifest, many of these changes will persist for hundreds or even thousands of years.
- In the committee's judgment, the risks associated with doing business as usual are a much greater concern than the risks associated with engaging in strong response efforts.

Methane is also a precursor to ground-level ozone, a health-harmful air pollutant. Additionally, ozone is a short-lived climate forcer that contributes to global warming. In remote areas, methane is a dominant precursor to tropospheric ozone formation.[26] Approximately 50 percent of the global annual mean ozone increase since preindustrial times is believed to be due to anthropogenic methane.[27] Projections of future emissions also indicate that methane is likely to be a key contributor to ozone concentrations in the future.[28] Unlike nitrogen oxide (NO_X) and VOC, which affect ozone concentrations regionally and at hourly time scales, methane emissions affect ozone concentrations globally and on decadal time scales given methane's relatively long atmospheric lifetime compared to these other ozone precursors.[29] Reducing methane emissions, therefore, may contribute to efforts to reduce global background ozone concentrations that contribute to the incidence of ozone-related health effects.[30] [31] These benefits are global and occur in both urban and rural areas.

2. VOC

Tropospheric, or ground-level, ozone is formed through reactions of VOC and NO_X in the presence of sunlight. Ozone formation can be controlled to some extent through reductions in emissions of ozone precursor VOC and NO_X. A significantly expanded body of scientific evidence shows that ozone can cause a number of harmful effects on health and the environment. Exposure to ozone can cause respiratory system effects such as difficulty breathing and airway inflammation. For people with lung diseases such as asthma and chronic obstructive pulmonary disease (COPD), these effects can lead to emergency room visits and hospital admissions. Studies have also found that ozone exposure is likely to cause premature death from lung or heart diseases. In addition, evidence indicates that long-term exposure to ozone is likely to result in harmful respiratory effects, including respiratory symptoms and the development of asthma. People most at risk from breathing air containing ozone include: Children; people with asthma and other respiratory diseases; older adults; and people who are active outdoors, especially outdoor workers. An estimated 25.9 million people have asthma in the U.S., including almost 7.1 million children. Asthma disproportionately affects children, families with lower incomes, and minorities, including Puerto Ricans, Native Americans/Alaska Natives and African-Americans.[32]

Scientific evidence also shows that repeated exposure to ozone reduces growth and has other harmful effects on plants and trees. These types of effects have the potential to impact ecosystems and the benefits they provide.

3. SO_2

Current scientific evidence links short-term exposures to SO_2, ranging from 5 minutes to 24 hours, with an array of adverse respiratory effects including bronchoconstriction and increased asthma symptoms. These effects are particularly important for

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[23] Blunden, J., and D.S. Arndt, Eds., 2014: State of the Climate in 2013. Bull. Amer. Meteor. Soc., 95 (7), S1–S238.

[24] *http://www.ncdc.noaa.gov/sotc/global/2014/13.*

[25] NRC, 2011: *America's Climate Choices,* The National Academies Press.

[26] U.S. EPA. 2013. ''Integrated Science Assessment for Ozone and Related Photochemical Oxidants (Final Report).'' EPA–600–R–10–076F. National Center for Environmental Assessment—RTP Division. Available at *http://www.epa.gov/ncea/isa/.*

[27] Myhre, G., D. Shindell, F.-M. Bréon, W. Collins, J. Fuglestvedt, J. Huang, D. Koch, J.-F. Lamarque, D. Lee, B. Mendoza, T. Nakajima, A. Robock, G. Stephens, T. Takemura and H. Zhang, 2013: Anthropogenic and Natural Radiative Forcing. In: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Pg. 680.

[28] *Ibid.*

[29] *Ibid.*

[30] West, J.J., Fiore, A.M. 2005. ''Management of tropospheric ozone by reducing methane emissions.''*Environ. Sci. Technol.* 39:4685–4691.

[31] Anenberg, S.C., *et al.* 2009. ''Intercontinental impacts of ozone pollution on human mortality,'' *Environ. Sci. & Technol.* 43:6482–6487.

[32] National Health Interview Survey (NHIS) Data, 2011 *http://www.cdc.gov/asthma/nhis/2011/data.htm.*

asthmatics at elevated ventilation rates (*e.g.,* while exercising or playing).

Studies also show an association between short-term exposure and increased visits to emergency departments and hospital admissions for respiratory illnesses, particularly in at-risk populations including children, the elderly, and asthmatics.

SO_2 in the air can also damage the leaves of plants, decrease their ability to produce food—photosynthesis—and decrease their growth. In addition to directly affecting plants, SO_2 when deposited on land and in estuaries, lakes and streams, can acidify sensitive ecosystems resulting in a range of harmful indirect effects on plants, soils, water quality, and fish and wildlife (*e.g.,* changes in biodiversity and loss of habitat, reduced tree growth, loss of fish species). Sulfur deposition to waterways also plays a causal role in the methylation of mercury.[33]

4. Emission Estimates

Section VI.A above explains how GHGs, VOC, and SO_2 emissions are ''air pollution'' that may reasonably be anticipated to endanger public health and welfare. This section provides estimated emissions that the oil and natural gas source category contributes to this air pollution. As shown below, the contribution from this industry is quite significant.

a. GHG Emissions

Atmospheric concentrations of GHGs are now at essentially unprecedented levels compared to the distant and recent past.[34] This is the unambiguous result of emissions of these gases from human activities. Global emissions of well-mixed GHGs have been increasing, and are projected to continue increasing for the foreseeable future. According to IPCC AR5, total global emissions of GHGs in 2010 were about 49,000 million metric tons [35] of CO2 equivalent (MMT CO2eq).[36] This represents an increase in global GHG emissions of about 29 percent since 1990 and 23 percent since 2000. In 2010, total U.S. GHG emissions were responsible for about 14 percent of global GHG emissions (and about 12 percent when factoring in the effect of carbon sinks from U.S. land use and forestry).

Based on the Inventory of U.S. Greenhouse Gas Emissions and Sinks Report [37] (hereinafter ''U.S. GHG Inventory''), in 2013 total U.S. GHG emissions increased by 5.9 percent from 1990 (or by about 4.8 percent when including the effects of carbon sinks), and increased from 2012 to 2013 by 2.0 percent. This increase was attributable to multiple factors including increased carbon intensity of fuels consumed to generate electricity, a relatively cool winter leading to an increase in heating requirements, an increase in industrial production across multiple sectors and a small increase in vehicle miles traveled (VMT) and fuel use across on-road transportation modes.

Because 2010 is the most recent year for which IPCC emissions data are available, we provide 2011 estimates from the World Resources Institute's (WRI) Climate Analysis Indicators Tool (CAIT) [38] for comparison. According to WRI/CAIT, the total global GHG emissions in 2011 were 43,816 MMT of CO_2 Eq., representing an increase in global GHG emissions of about 42 percent since 1990 and 30 percent since 2000 (excluding land use, land use change and forestry). These estimates are generally consistent with those of IPCC. In 2011, WRI/CAIT data indicate that total U.S. GHG emissions were responsible for almost 15.5 percent of global emissions, which is also generally in line with the percentages using IPCC's 2010 estimate described above. According to WRI/CAIT, current U.S. GHG emissions rank only behind China's, which was responsible for 24 percent of total global GHG emissions.

i. Methane Emissions in the United States and from the Oil and Natural Gas Industry

The GHGs addressed by the 2009 Endangerment Finding consist of six well-mixed gases, including methane. Methane is a potent GHG with a 100 year GWP that is 28–36 times greater than that of carbon dioxide.[39] Methane has an atmospheric life of about 12 years. Official U.S. estimates of national level GHG emissions and sinks are developed by the EPA for the U.S. GHG Inventory to comply with commitments under the United Nations Framework Convention on Climate Change (UNFCCC). The U.S. inventory, which includes recent trends, is organized by industrial sectors. Natural gas and petroleum systems are the largest emitters of methane in the U.S. These systems emit 29 percent of U.S. anthropogenic methane.

Table 2 below presents total U.S. anthropogenic methane emissions for the years 1990, 2005 and 2013.

TABLE 2—U.S. METHANE EMISSIONS BY SECTOR

[Million metric ton carbon dioxide equivalent (MMT CO_2 Eq.)]

Sector	1990	2005	2013
Oil and Natural Gas Production, and Natural Gas Processing and Transmission	170.0	163.5	148.3
Enteric Fermentation	164.2	168.9	164.5
Landfills	186.2	165.5	114.6
Coal Mining	96.5	64.1	64.6
Manure Management	37.2	56.3	61.4
Other Methane Sources [40]	91.4	89.5	82.9

[33] U.S. EPA. Integrated Science Assessment (ISA) for Oxides of Nitrogen and Sulfur Ecological Criteria (2008 Final Report). U.S. Environmental Protection Agency, Washington, DC, EPA/600/R–08/082F, 2008.

[34] IPCC, 2013: *Summary for Policymakers. In: Climate Change 2013: The Physical Science Basis.* Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, p. 11.

[35] One MMT = 1 million metric tons = 1 megatonne (Mt). 1 metric ton = 1,000 kg = 1.102 short tons = 2,205 lbs.

[36] IPCC, 2014: *Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change* [Edenhofer, O., R. Pichs-Madruga, Y. Sokona, E. Farahani, S. Kadner, K. Seyboth, A. Adler, I. Baum, S. Brunner, P. Eickemeier, B. Kriemann, J. Savolainen, S. Schlömer, C. von Stechow, T. Zwickel and J.C. Minx (eds.)]. Cambridge University Press, 1435 pp.

[37] U.S. EPA, 2014: *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2012.* Available at *http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html#fullreport* (Last accessed January 29, 2015).

[38] World Resources Institute (WRI) Climate Analysis Indicators Tool (CAIT) Data Explorer (Version 2.0). Available at *http://cait.wri.org.* (Last accessed October 31, 2014.)

[39] IPCC, 2013: Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change [Stocker, T.F., D. Qin, G.-K. Plattner, M. Tignor, S.K. Allen, J. Boschung, A. Nauels, Y. Xia, V. Bex and P.M. Midgley (eds.)]. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA, 1535 pp. Note that for purposes of inventories and reporting, GWP values from the 4th Assessment Report may be used.

TABLE 2—U.S. METHANE EMISSIONS BY SECTOR—Continued

[Million metric ton carbon dioxide equivalent (MMT CO_2 Eq.)]

Sector	1990	2005	2013
Total Methane Emissions	745.5	707.8	636.3

Emissions from the U.S. GHG Inventory, calculated using GWP of 25.

Oil and natural gas production and natural gas processing and transmission systems encompass wells, natural gas gathering and processing facilities, storage, and transmission pipelines. These components are all important aspects of the natural gas cycle—the process of getting natural gas out of the ground and to the end user. In the oil industry, some underground crude oil contains natural gas that is entrained in the oil at high reservoir pressures. When oil is removed from the reservoir, associated natural gas is produced.

Methane emissions occur throughout the natural gas industry. They primarily result from normal operations, routine maintenance, fugitive leaks and system upsets. As gas moves through the system, emissions occur through intentional venting and unintentional leaks. Venting can occur through equipment design or operational practices, such as the continuous bleed of gas from pneumatic controllers (that control gas flows, levels, temperatures, and pressures in the equipment), or venting from well completions during production. In addition to vented emissions, methane losses can occur from leaks (also referred to as fugitive emissions) in all parts of the infrastructure, from connections between pipes and vessels, to valves and equipment.

In petroleum systems, methane emissions result primarily from field production operations, such as venting of associated gas from oil wells, oil storage tanks, and production-related equipment such as gas dehydrators, pig traps, and pneumatic devices.

Table 3 (a and b) below present total methane emissions from natural gas and petroleum systems, and the associated segments of the sector, for years 1990, 2005 and 2013, in million metric tons of carbon dioxide equivalent (Table 3(a)) and kilotons (or thousand metric tons) of methane (Table 3(b)).

TABLE 3(a)—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[MMT CO_2 Eq.]

Sector	1990	2005	2013
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	170	163	148
Natural Gas Production	59	75	47
Natural Gas Processing	21	16	23
Natural Gas Transmission and Storage	59	49	54
Petroleum Production	31	23	24

Emissions from the 2015 U.S. GHG Inventory, calculated using GWP of 25.

TABLE 3(b)—U.S. METHANE EMISSIONS FROM NATURAL GAS AND PETROLEUM SYSTEMS

[kt CH_4]

Sector	1990	2005	2013
Oil and Natural Gas Production and Natural Gas Processing and Transmission (Total)	6,802	6,539	5,930
Natural Gas Production	2,380	3,018	1,879
Natural Gas Processing	852	655	906
Natural Gas Transmission and Storage	2,343	1,963	2,176
Petroleum Production	1,227	903	969

Emissions from the 2015 U.S. GHG Inventory, in kt (1,000 tons) of CH4.

ii. U.S. Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total U.S. GHG Emissions

Relying on data from the U.S. GHG Inventory, we compared U.S. oil and natural gas production and natural gas processing and transmission GHG emissions to total U.S. GHG emissions as an indication of the role this source plays in the total domestic contribution to the air pollution that is causing climate change. In 2013, total U.S. GHG emissions from all sources were 6,673 MMT CO_2 Eq.

For purposes of the proposed revision to the category listing, the EPA is including oil and natural gas production sources, and natural gas processing transmission sources. In 2013, emissions from oil and natural gas production sources and natural gas processing and transmission sources accounted for 148 MMT CO_2eq methane emissions and oil completions for another 3 MMT CO2eq (using a GWP of 25 for methane). The sector also emitted 44 MMT of CO_2, mainly from acid gas removal during natural gas processing (22 MMT) and flaring in oil and natural gas production (16 MMT). In total, these emissions account for 3.0 percent of total U.S. domestic emissions.

In regard to the six well-mixed GHGs (CO_2, methane, nitrous oxide,

[40] Other sources include remaining natural gas distribution, petroleum transport and petroleum refineries, forest land, wastewater treatment, rice cultivation, stationary combustion, abandoned coal mines, petrochemical production, mobile combustion, composting, and several sources emitting less than 1 MMT CO_2-e in 2013.

hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride), only two of these gases—CO_2 and methane—are reported as non-zero emissions for the oil and natural gas production sources and natural gas processing and transmission sources that are being addressed within this rule.

TABLE 4—COMPARISONS OF U.S. OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION GHG EMISSIONS TO TOTAL U.S. GHG EMISSIONS

	2010	2011	2012	2013
Total U.S. Oil & Gas Production and Natural Gas Processing & Transmission GHG Emissions (MMT CO_2 Eq)	147	147	146	148
Share of Total U.S. GHG Inventory	2.13%	2.18%	2.23%	2.22%
Total U.S. GHG Emissions (MMT CO_2 Eq)	6,899	6,777	6,545	6,673

iii. U.S. Oil and Natural Gas Production and Natural Gas Processing and Transmission GHG Emissions Relative to Total Global GHG Emissions

TABLE 5—COMPARISONS OF U.S. OIL AND NATURAL GAS PRODUCTION AND NATURAL GAS PROCESSING AND TRANSMISSION GHG EMISSIONS TO TOTAL GLOBAL GREENHOUSE GAS EMISSIONS IN 2010

	2010 (MMT CO_2 eq)	Total U.S. oil and natural gas production and natural gas processing and transmission share (%)
Total Global GHG Emissions	49,000	0.3%

For additional background information and context, we used 2011 WRI/CAIT and IEA data to make comparisons between U.S. oil and natural gas production and natural gas processing and transmission emissions and the emissions inventories of entire countries and regions. Ranking U.S. emissions of GHGs from oil and natural gas production and natural gas processing and transmission against total GHG emissions for entire countries, show that these emissions would be more than the national-level emissions totals for all anthropogenic sources for Greece, the Czech Republic, Chile, Belgium, and about 140 other countries.

As illustrated by the data summarized above, the collective GHG emissions from oil and natural gas production and natural gas processing and transmission sources are significant, whether the comparison is domestic (3.0 percent of total U.S. emissions) or global (0.3 percent of all global GHG emissions). The EPA believes that consideration of the global context is important. GHG emissions from U.S. oil and natural gas production and natural gas processing and transmission will become globally well-mixed in the atmosphere, and thus will have an effect on the U.S. regional climate, as well as the global climate as a whole for years and indeed many decades to come. Based on the data above, GHG emissions from the oil and natural gas source category is significiant whether only the domestic context is considered, only the global context is considered, or both the domestic and global GHG emissions comparisons are viewed in combination.

As was the case in 2009, no single GHG source category dominates on the global scale, and many (if not all) individual GHG source categories could appear small in comparison to the total, when, in fact, they could be very important contributors in terms of both absolute emissions or in comparison to other source categories, globally or within the U.S. Contributions of GHG to the global problem should not be compared to contributions associated with local air pollution problems. The EPA continues to believe that these unique, global aspects of the climate change problem—including that from a percentage perspective there are no dominating sources emitting GHGs and fewer sources that would even be considered to be close to dominating—tend to support consideration of contribution to the air pollution at lower percentage levels than the EPA typically encounters when analyzing contribution towards a more localized air pollution problem. Thus, the EPA, similar to the approach taken in the 2009 Finding, is placing significant weight on the fact that oil and natural gas production and natural gas processing and transmission sources contribute 3 percent of total U.S. GHG emissions for the contribution finding.

b. VOC Emissions

The EPA National Emissions Inventory (NEI) estimated total VOC emissions from the oil and natural gas sector to be 2,782,000 tons in 2011. This ranks second of all the sectors estimated by the NEI and first of all the anthropogenic sectors in the NEI.

c. SO_2 Emissions

The NEI estimated total SO_2 emissions from the oil and natural gas sector to be 74,000 tons in 2011. This ranks 13th of the sectors estimated by the NEI.

5. Conclusion

In summary, EPA interprets the 1979 category listing to broadly cover the oil and natural gas industry, including all segments of the natural gas industry (production, processing, transmission, and storage). To the extent there is ambiguity to the prior listing, EPA is proposing to revise the category listing to include the various segments of the natural gas industry. In support, EPA notes its previous determination under section 111(b)(1)(A) for the oil and natural gas source category. In addition, EPA provides in this section information and analyses detailing the public health and welfare impacts of GHG, VOC and SO_2 emissions and the amount of these emission from the oil and natural gas source category (in particular from the various segments of the natural gas industry). Although EPA does not believe the proposed revision to the category listing is required for the standards we are proposing in this action, even assuming it is, the proposal is well justified.

B. Stakeholder Input

1. White Papers

As a follow up to the 2013 Climate Action Plan, the Climate Action Plan: Strategy to Reduce Methane Emissions (the Methane Strategy) was released in March 2014. The Methane Strategy instructed the EPA to release a series of white papers on several potentially significant sources of methane in the oil and natural gas sector and solicit input from independent experts. The papers were released in April 2014, and focused on technical issues, covering emissions and control technologies that target both VOC and methane with particular focus on completions of hydraulically fractured oil wells, liquids unloading, leaks, pneumatic devices and compressors. The peer review process was completed on June 16, 2014.

The peer review and public comments on the white papers included additional technical information that provided further clarification of our understanding of the emission sources and emission control options. The comments also provided additional data on emissions and number of sources, and pointed out newly published studies that further informed our emission rate estimates. Where appropriate, we used the information and data provided to adjust the control options considered and the impacts estimates presented in the 2015 TSD.

The EPA used an ad hoc external peer review process, as outlined in the EPA's Peer Review Handbook, 3rd Edition. Under that process, the Agency submitted names recommended by industry and environmental groups, along with state, tribal, and academic organizations to an outside contractor. To avoid any conflict of interest, the contractor did not work on the white papers and is not working on the EPA's oil and natural gas regulations or voluntary programs. The contractor built a list of qualified reviewers from these names and their own research, reviewed appropriate credentials and selected reviewers from the list. A different set of reviewers was selected for each white paper, based on the reviewers' expertise. A total of 26 sets of comments from peer reviewers were submitted to the EPA. Additionally, the EPA solicited technical information and data from the public. The EPA received over 43,000 submissions from the public. The comments received from the peer reviewers are available on EPA's oil and natural gas white paper Web site (*http://www.epa.gov/airquality/oilandgas/methane.html*). Public comments on the white papers are available in EPA's nonregulatory docket at *www.regulations.gov*, docket ID # EPA–HQ–OAR–2014–0557.

2. Outreach to State, Local and Tribal Governments

The EPA spoke with state, local and tribal governments to hear how they have managed issues, and to get feedback that would help us as we develop the rule. In February 2015, the EPA asked states and tribes to nominate themselves to participate in discussions. Twelve states, three tribes and several local air districts participated. We conducted several teleconferences in March and April 2015 to discuss such questions as:

- Whether these governments are, or have considered, regulating the sources identified in the white papers
- Factors considered in determining whether to regulate them
- Use of innovative compliance options
- Experiences implementing control techniques guidelines (CTGs) [41]
- Information and features that would be helpful to include in a CTG
- Whether any sources of emissions are particularly suitable to voluntary rather than regulatory action

In addition to the outreach described above, the EPA consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to provide them with the opportunity to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process and provided an update on the methane strategy to the National Tribal Air Association. Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

[41] Control techniques guidelines are not part of this action.

VII. Summary of Proposed Standards

A. Control of Methane and VOC Emissions in the Oil and Natural Gas Source Category

In this action, we propose to set emission standards for methane and VOC for certain new, modified and reconstructed emission sources across the oil and natural gas source category. For some of these sources, there are VOC requirements currently in place that were established in the 2012 NSPS, that we are expanding to include methane. For others, for which there are no current requirements, we are proposing methane and VOC standards. We are also proposing improvements to enhance implementation of the current standards. For the reasons explained in section V, EPA believes that the proposed methane standards are warranted, even for those already subject to VOC standards under the 2012 NSPS. Further, as shown in the analyses in section VIII, there are cost effective controls that achieve simultaneous reductions of methane and VOC emission. Some stakeholders have advocated that is appropriate to rely on VOC standards, as established in 2012, for sources in the production and processing segment. For example, based on methane and VOC emissions from pneumatic controllers, this approach could result in just a VOC standard for pneumatic controllers in the production segment and a VOC and methane standard in the transmission and storage segment. Some stakeholders have also advocated for the importance of setting methane standards in the production segment that go beyond the 2012 NSPS standards. We anticipate that these stakeholders will express their views during the comment period.

Pursuant to CAA section 111(b), we are proposing to amend subpart OOOO and to create a new subpart OOOOa which will include the standards and requirements summarized in this section. Subpart OOOO would be amended to apply to facilities constructed, modified or reconstructed after August 23, 2011, (*i.e.*, the original proposal date of subpart OOOO) and before September 18, 2015 (*i.e.*, the proposal date of the new subpart OOOOa) and would be amended only to include the revisions reflecting implementation improvements in response to issues raised in petitions for reconsideration. Subpart OOOOa would apply to facilities constructed, modified or reconstructed after September 18, 2015 and would include current VOC requirements already provided in subpart OOOO as well as new provisions for methane and VOC across the oil and natural gas source category as highlighted below in this section. More details of the rationale for these proposed standards and requirements are provided in section VIII of this preamble.

We note that the terms ''emission source,'' ''source type'' and ''source,'' as used in this preamble, refer to equipment, processes and activities that emit VOC and/or methane. This term does not refer to specific facilities, in contrast to usage of the term ''source'' in the contexts of permitting and section 112 actions. As summarized below and discussed in more detail in section VIII, the BSER for methane is the same as that for VOC for all emission sources, including those currently subject to VOC standards and for which we are proposing to establish methane standards in this action. Accordingly, the current requirements reflect the BSER for both VOC and methane for these sources. We are, therefore, not proposing any change to the current requirements for emission sources addressed under the 2012 NSPS.

Both VOC and methane are hydrocarbon compounds and behave essentially the same when emitted together or separately. Accordingly, the available controls for methane are the same as those for VOC and achieve the same levels of reduction for both VOC and methane. For example, combustion-based control technologies (*e.g.*, flares and enclosed combustors) that reduce VOC emissions by 95 percent can be expected to also reduce methane emissions by 95 percent. Similarly, work practice and operational standards (*e.g.*, leak detection and reduced emission completion of wells) that reduce emissions of VOC can be expected to have the same effect on methane emissions. Because VOC control technologies perform the same when used to control methane emissions, the BSER for methane is the same as the BSER for VOC. Therefore, we are proposing performance and operational standards to control methane and VOC emissions for certain emission sources across the source category. These proposed methane standards would require no change to the requirements for currently regulated affected facilities.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently (*e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

B. Centrifugal Compressors

We are proposing standards to reduce methane and VOC emissions from new, modified or reconstructed centrifugal compressors located across the oil and natural gas source category, except those located at well sites. As discussed in detail in section VIII.B, the proposed standards are the same as those currently required to control VOC from centrifugal compressors in the production segment. Specifically, we are proposing to require 95 percent reduction of the emissions from each wet seal centrifugal compressor affected facility. The standard can be achieved by capturing and routing the emissions utilizing a cover and closed vent system to a control device that achieves an emission reduction of 95 percent, or routing the captured emissions to a process. Consistent with the current VOC provisions for centrifugal compressors in the production segment, dry seal centrifugal compressors are inherently low-emitting and would not be affected facilities. These proposed standards are the same as for centrifugal compressors regulated in the 2012 final rule.

C. Reciprocating Compressors

For the reasons discussed in section VIII.C, we are proposing an operational standard for affected reciprocating compressors across the oil and natural gas source category, except those located at well sites, that requires either replacement of the rod packing based on usage or routing of rod packing emissions to a process via a closed vent system under negative pressure. The owner or operator of a reciprocating compressor affected facility would be required to monitor the duration (in hours) that the compressor is operated, beginning on the date of initial startup of the reciprocating compressor affected facility. When the hours of operation reach 26,000 hours, the owner or operator would be required to immediately change the rod packing. Owners or operators can elect to change the rod packing every 36 months in lieu of monitoring compressor operating hours. As an alternative to rod packing replacement, owners and operators may route the rod packing emissions to a process via a closed vent system operated at negative pressure. These proposed standards are the same as for reciprocating compressors regulated in the 2012 rule.

D. Pneumatic Controllers

For the reasons presented in section VIII.D, consistent with VOC standards in the 2012 NSPS for pneumatic controllers in the production segment, we are proposing to control methane and VOC emissions by requiring use of low-bleed controllers in place of high-bleed controllers *(i.e.*, natural gas bleed rate not to exceed 6 scfh)[42] at locations within the source category except for natural gas processing plants. For natural gas processing plants, consistent with the VOC emission standards in the 2012 NSPS, we are proposing to control methane and VOC emissions by requiring that pneumatic controllers have zero natural gas bleed rate (*i.e.*, they are operated by means other than natural gas, such as being driven by compressed instrument air). We are proposing that these standards apply to each newly installed, modified or reconstructed pneumatic controller (including replacement of an existing controller). Consistent with the current requirements under the 2012 NSPS for control of VOC emissions from pneumatic controllers in the production segment and at natural gas processing plants, the proposed standards provide exemptions for certain critical applications based on functional considerations. These proposed standards are the same as for pneumatic controllers regulated in the 2012 rule.

E. Pneumatic Pumps

For the reasons detailed in section VIII.E, we are proposing standards for natural gas-driven chemical/methanol pumps and diaphragm pumps. The proposed standards would require the methane and VOC emissions from new, modified and reconstructed natural gas-driven chemical/methanol pumps and diaphragm pumps located at any location (except for natural gas processing plants) throughout the source category to be reduced by 95 percent if a control device is already available on site. For pneumatic pumps located at a natural gas processing plant, the proposed standards would require the methane and VOC emissions from natural gas-driven chemical/methanol pumps and diaphragm pumps to be zero.

F. Well Completions

We are proposing operational standards for well completions at hydraulically fractured (or refractured) wells, including oil wells. The 2012 NSPS regulated well completions to

[42] Bleed rate can be documented through information provided by the controller manufacturer.

control VOC emissions from hydraulically fractured or refractured gas wells. These proposed standards are the same as for natural gas wells regulated in the 2012 rule. We identified two subcategories of hydraulically fractured wells for which well completions are conducted: (1) Non-wildcat and non-delineation wells; and (2) wildcat and delineation wells. A wildcat well, also referred to as an exploratory well, is a well drilled outside known fields or are the first well drilled in an oil or gas field where no other oil and gas production exists. A delineation well is a well drilled to determine the boundary of a field or producing reservoir.

As discussed in detail in section VIII.F, we are proposing operational standards for subcategory 1 (non-wildcat, non-delineation wells) requiring a combination of REC and combustion. Compared to combustion alone, we believe that the combination of REC and combustion will maximize gas recovery and minimize venting to the atmosphere. Furthermore, the use of traditional combustion control devices (*i.e.*, flares and enclosed combustion control devices), present local emissions impacts. The proposed standards for subcategory 2 wells (wildcat and delineation wells) require only combustion. For subcategory 1 wells, we are proposing to define the flowback period of an oil well completion as consisting of two distinct stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the onset of flowback and ends when the flow is routed to a separator. During the initial flowback stage, any gas in the flowback is not subject to control. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. The point at which the separator can function marks the beginning of the separation flowback stage. During this stage, the operator must route all salable quality gas from the separator to a flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose. If it is technically infeasible to route the gas as described above, or if the gas is not of salable quality, the operator must combust the gas unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. No direct venting of gas is allowed during the separation flowback stage. The separation flowback stage ends either when the well is shut in and the flowback equipment is permanently disconnected from the well, or on startup of production. This also marks the end of the flowback period. The operator has a general duty to safely maximize resource recovery safely and minimize releases to the atmosphere over the duration of the flowback period. The operator is also required to document the stages of the completion operation by maintaining records of (1) the date and time of the onset of flowback; (2) the date and time of each attempt to route flowback to the separator; (3) the date and time of each occurrence in which the operator reverted to the initial flowback stage; (4) the date and time of well shut in; and (5) date and time that temporary flowback equipment is disconnected. In addition, the operator must document the total duration of venting, combustion and flaring over the flowback period. All flowback liquids during the initial flowback period and the separation flowback period must be routed to a well completion vessel, a storage vessel or a collection system.

For subcategory 2 wells, we are proposing an operational standard that requires routing of the flowback into well completion vessels and commencing operation of a separator unless it is technically infeasible for the separator to function. Once the separator can function, recovered gas must be captured and directed to a completion combustion device unless combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. Operators would be required to maintain the same records described above for category 1 wells.

Consistent with the current VOC standards for hydraulically fractured gas wells, we are proposing that ''low pressure'' wells would remain affected facilities and would have the same requirements as subcategory 2 wells (wildcat and delineation wells). The term ''low pressure gas well'' is unchanged from the currently codified definition in the NSPS; however, we solicit comment on whether this definition appropriately indicates hydraulically fractured oil wells for which conducting an REC would be technologically infeasible and whether the term should be revised to address all wells rather than just gas wells.

We are also retaining the provision from the 2012 NSPS, now at § 60.5365a(a)(1), that a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through (4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We point out that such an exclusion of a ''well'' from applicability under the NSPS has no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards at § 60.5397a.

Further, we are proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS. We solicit comment on whether a GOR of 300 is the appropriate applicability threshold. Rationale for this threshold is discussed in detail in section VIII.F.

G. Fugitive Emissions From Well Sites and Compressor Stations

1. Fugitive Emissions From Oil and Natural Gas Production Well Sites

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified oil and natural gas production well sites. The proposed standards would require locating and repairing sources of fugitive emissions (*e.g.*, visible emissions from fugitive emissions components observed using OGI) at well sites. Under the proposed standards, the affected facility would be ''the collection of fugitive emissions components at a well site''; where ''well site'' is defined in subpart OOOO as ''one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, gas well, or injection well and its associated well pad.'' This definition is intended to include all ancillary equipment in the immediate vicinity of the well that are necessary for or used in production, and may include such items as separators, storage vessels, heaters, dehydrators, or other equipment at the site.

Some well sites, especially in areas with very dry gas or where centralized gathering facilities are used, consist only of one or more wellheads, or ''Christmas trees,'' and have no ancillary equipment such as storage vessels, closed vent systems, control devices, compressors, separators and pneumatic controllers. Because the magnitude of fugitive emissions depends on how many of each type of component *(e.g.*, valves, connectors and pumps) are present, fugitive emissions from these well sites are extremely low. For that reason, we are proposing to exclude from the fugitive emissions requirements those well sites that contain only wellheads. Therefore, we are proposing to add the following sentence to the definition of ''well site'' above: ''For the purposes of the fugitive emissions standards at § 60.5397a, a well site that only contains one or more wellheads is not subject to these standards.''

Also, we are proposing to exclude low production well sites (*i.e.*, a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) from the standards for fugitives emissions from well sites. Please refer to section VIII.G. for further discussion.

We are proposing that owners or operators of well site-affected facilities conduct an initial survey of ''fugitive emissions components,'' which we are proposing to define in § 60.5430a to include, among other things, valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks using either OGI technology. For new well sites, the initial survey would have to be conducted within 30 days of the end of the first well completion or upon the date the site begins production, whichever is later. For modified well sites, the initial survey would be required to be conducted within 30 days of the site modification. We solicit comment on whether 30 days is an appropriate period for the first survey following startup or modification. For the purposes of these fugitive emissions standards, a modification would occur when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. See section VII.G.3 below for a discussion of modifications in the context of fugitive emission requirements for well sites and compressor stations. After the initial monitoring survey, monitoring surveys would be required to be conducted semiannually for all new and modified well sites. We are also co-proposing monitoring surveys on an annual basis for new and modified well sites.

The proposed standards would require replacement or repair of components if evidence of fugitive emissions is detected during the monitoring survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting the repair or replacement. All sources of fugitive emissions that are repaired must be resurveyed within 15 days of repair completion to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. A company would be able to develop a corporate-wide monitoring plan, although there may be specific information needed that pertains to a single site, such as number and identification of fugitive emission components. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected at less than one percent of the fugitive emission components at a well site during two consecutive semiannual monitoring surveys, then the monitoring survey frequency for that well site may be reduced to annually. If, during a subsequent monitoring survey, fugitive emissions are detected at between one percent and three percent of the fugitive emission components, then the monitoring survey frequency for that well site must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components at a well site during two consecutive semiannual monitoring, then the monitoring survey frequency for that well site must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action. We also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology with semiannual survey monitoring as the BSER for detecting fugitive emissions from new and modified well sites.

The proposed standards would apply to new well sites and to modified well sites. As explained in more detail in section VIII.B below, for purposes of this proposed standard, a well site is modified when a new well is completed (regardless of whether it is fractured) or an existing well is fractured or refractured after [effective date of final rule]. The standards would not apply to existing well sites where additional drilling activities were conducted on an existing well but those activities did not include fracturing or refracturing (e.g., well workovers that do not include fracturing or refracturing).

2. Fugitive Emissions From Compressor Stations

We are proposing standards to reduce fugitive methane and VOC emissions from new and modified natural gas compressor stations throughout the oil and natural gas source category. The proposed standards would require affected facilities to locate sources of fugitive emissions and to repair those sources. We are proposing that owners or operators of the affected facilities conduct an initial survey of the collection of fugitive emissions components (*e.g.,* valves, connectors, open-ended lines, pressure relief devices, closed vent systems and thief hatches on tanks) using OGI technology. For new compressor stations, the initial survey would have to be conducted within 30 days of site startup. For modified compressor stations, the initial survey would be required within 30 days of the site modification. After the initial survey, surveys would be required semiannually. We solicit comment on whether 30 days is an appropriate period for the first survey following startup.

The proposed standards would require replacement or repair of any fugitive emissions component that has evidence of fugitive emissions detected during the survey through visible confirmation from OGI. As discussed in section VIII.G, we solicit comment on whether to allow EPA Method 21 as an alternative to OGI for monitoring, including the appropriate EPA Method 21 level repair threshold.

We are proposing that the source of emissions be repaired or replaced, and resurveyed, as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We expect that the majority of the repairs can be made at the time the initial monitoring survey is conducted. However, we understand that more time may be necessary to repair more complex components. We have historically allowed 15 days for repair/resurvey in the LDAR program, which has appeared to be sufficient time. We are proposing to allow the use of either Method 21 or OGI for resurveys that cannot be performed during the initial monitoring survey and repair. As explained above, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. For those components that have been repaired, we believe that the no fugitive emissions would be detected above 500 ppm above background using Method 21. This has been historically used to ensure that there are no emissions from components that are required to operate with no detectable emissions. We solicit comments on whether either optical gas imaging or Method 21 should be allowed for the resurvey of the repaired components when fugitive emissions are detected with OGI. We estimate that the majority of operators will need to hire a contractor to come back to conduct the optical gas imaging resurvey. While there will also be costs associated with resurveying using Method 21, we estimate that many companies own Method 21 instruments (*e.g.,* OVA/TVA) and would be able to perform the resurvey at a minimal cost. To verify that the repair has been made using OGI, no evidence of visible emissions must be seen during the survey. For Method 21, we are proposing that the instrument show a reading of less than 500 ppm above background from any of the repaired components. We solicit comment whether 500 ppm above background is the appropriate repair resurvey threshold when Method 21 instruments are used or if not, what the appropriate repair resurvey threshold is for Method 21.

The source of emissions must be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe during unit operations, the repair or replacement must be completed during the next scheduled shutdown or within six months, whichever is earlier. Equipment is unsafe to repair or replace if personnel would be exposed to an immediate danger in conducting monitoring. All sources of fugitive emissions that are repaired must be resurveyed to ensure the repair has been successful (*i.e.,* no fugitive emissions are imaged using OGI or less than 500 ppm above background when using Method 21).

The EPA is proposing that these fugitive emission requirements be carried out through the development and implementation of a monitoring plan, which would specify the measures for locating sources of fugitive emissions and the detection technology to be used. The monitoring plan must also include a description of how the OGI survey will be conducted that ensures that fugitive emissions can be imaged effectively. In addition, we solicit comment on whether other techniques could be required elements of the monitoring plan in conjunction with OGI, such as visual inspections, to help identify signs such as staining of storage vessels or other indicators of potential leaks or improper operation.

If fugitive emissions are detected during two consecutive semi-annual monitoring surveys at less than one percent of the fugitive emission components, then the monitoring survey frequency for that compressor station may be reduced to annually. If, during a subsequent monitoring survey, visible fugitive emissions are detected using OGI from one to three percent of the fugitive emission components, then the monitoring survey frequency for that compressor station must be increased to semiannually.

If fugitive emissions are detected from three percent or more of the fugitive emission components during two consecutive semiannual monitoring surveys with OGI technology, then the monitoring survey frequency for that compressor station must be increased to quarterly. If, during a subsequent monitoring survey, fugitive emissions are detected from one to three percent of the fugitive emission components using OGI technology, then the monitoring survey frequency for that compressor station may be reduced to semiannually. If fugitive emissions are detected from less than one percent of the fugitive emission components, then the monitoring survey frequency for that well site may be reduced to annually. We solicit comment on the proposed metrics of one percent and three percent and whether these thresholds should be specific numbers of components rather than percentages of components for triggering change in survey frequency discussed in this action. We also solicit comment on whether a performance-based frequency or a fixed frequency is more appropriate.

As discussed in more detail in section VIII.G below and the TSD for this action available in the docket, we have identified OGI technology as the BSER for detecting fugitive emissions from new and modified compressor stations.

The proposed standards apply to new and modified compressor stations throughout the oil and natural gas source category. As explained in section VII.G.3 below, compressor stations are considered modified for the purposes of these fugitive emission standards when one or more compressors is added to the station after [effective date of final rule].

3. Modification of the Collection of Fugitive Emissions Components at Well Sites and Compressor Stations

For the purposes of the fugitive emission standards at well sites and compressor stations, we are proposing definitions of ''modification'' for those facilities that are specific to these provisions and for this purpose only. As provided in section 60.14(f), such provisions in the specific subparts would supersede any conflicting provisions in § 60.14 of the General Provisions. This definition does not affect other standards under this subpart for wells, other equipment at well sites or compressors.

For purposes of the proposed fugitive emissions standards at well sites, we propose that a modification to a well site occurs only when a new well is added to a well site (regardless of whether the well is fractured) or an existing well on a well site is fractured or refractured. When a new well is added or a well is fractured or refractured, there is an increase in emissions to the fugitive emissions components because of the addition of piping and ancillary equipment to support the well, along with potentially greater pressures and increased production brought about by the new or fractured well. Other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites. We note that under § 60.5365a(a)(1) a well that is refractured, and for which the well completion operation is conducted according to the requirements of § 60.5375a(a)(1) through(4), is not considered a modified well and therefore does not become an affected facility under the NSPS. We would like to clarify that such an exclusion of a ''well'' from applicability under the NSPS would have no effect on the affected facility status of the ''well site'' for purposes of the proposed fugitive emissions standards. Accordingly, a well at an existing well site that is refractured constitutes a modification of the well site, which then would be an affected facility for purposes of the fugitive emission standards at § 60.5397a, regardless of whether the well itself is an affected facility.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (*i.e.* green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit comment on criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.,* how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites or compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites or compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these well sites and compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

For purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. Since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To clarify and ease implementation, we define ''modification'' as the addition of a compressor for purposes of the fugitive emissions provisions at compressor stations.

H. Equipment Leaks at Natural Gas Processing Plants

We are proposing standards to control methane and VOC emissions from equipment leaks at natural gas processing plants. These requirements are the same as the VOC equipment leak requirements in the 2012 NSPS and would require NSPS part 60, subpart VVa level of control, including a detection level of 500 ppm as in the 2012 NSPS. As discussed further in section VIII.H, we propose that the subpart VVa level of control applied plant-wide is the BSER for controlling methane emissions from equipment leaks at onshore natural gas processing plants. We believe it provides the greatest emission reductions of the options we considered in our analysis in Section VIII.H, and that the costs are reasonable.

I. Liquids Unloading Operations

For the reasons discussed in section VIII.I, at this time the EPA does not have sufficient information to propose a standard for liquids unloading. However, we are requesting comment on nationally applicable technologies and techniques that reduce methane and VOC emissions from these events.

Specifically, we request comment on technologies and techniques that can be applied to new gas wells that can reduce emissions from liquids unloading in the future.

J. Recordkeeping and Reporting

We are proposing recordkeeping and reporting requirements that are consistent with those required in the current NSPS for natural gas well completions, compressors and pneumatic controllers. Owners or operators would be required to submit initial notifications (except for wells, pneumatic controllers, pneumatic pumps and compressors, as provided in § 60.5420(a)(1)) and annual reports, and to retain records to assist in documenting that they are complying with the provisions of the NSPS.

For new, modified or reconstructed pneumatic controllers, owners and operators would not be required to submit an initial notification; they would simply need to report the installation of these affected facilities in their facility's first annual report following the compliance period during which they were installed. Owners or operators of well-affected facilities (consistent with current requirements for gas well affected facilities) would be required to submit an initial notification no later than two days prior to the commencement of each well completion operation. This notification would include contact information for the owner or operator, the American Petroleum Institute (API) well number, the latitude and longitude coordinates for each well, and the planned date of the beginning of flowback.

In addition, an initial annual report would be due no later than 90 days after the end of the initial compliance period, which is established in the rule. Subsequent annual reports would be due no later than the same date each year as the initial annual report. The annual reports would include information on all affected facilities owned or operated of sources that were constructed, modified or reconstructed during the reporting period. A single report may be submitted covering multiple affected facilities, provided that the report contains all the information required by 40 CFR 60.5420(b). This information would include general information on the facility (*i.e.*, company name and address, etc.), as well as information specific to individual affected facilities.

For well affected facilities, the information required in the annual report would include the location of the well, the API well number, the date and time of the onset of flowback following hydraulic fracturing or refracturing, the date and time of each attempt to direct flowback to a separator, the date and time of each occurrence of returning to the initial flowback stage, and the date and time that the well was shut in and the flowback equipment was permanently disconnected or the startup of production, the duration of flowback, the duration of recovery to the flow line, duration of combustion, duration of venting, and specific reasons for venting in lieu of capture or combustion. For each oil well for which an exemption is claimed for conditions in which combustion may result in a fire hazard or explosion or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways, the report would include the location of the well, the API well number, the specific exception claimed, the starting date and ending date for the period the well operated under the exception, and an explanation of why the well meets the claimed exception. The annual report would also include records of deviations where well completions were not conducted according to the applicable standards.

For centrifugal compressor affected facilities, information in the annual report would include an identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period, as well as records of deviations in cases where the centrifugal compressor was not operated in compliance with the applicable standards.

For reciprocating compressors, information in the annual report would include the cumulative number of hours of operation or the number of months since initial startup or the previous reciprocating compressor rod packing replacement, whichever is later, or a statement that emissions from the rod packing are being routed to a process through a closed vent system under negative pressure.

Information in the annual report for pneumatic controller affected facilities would include location and documentation of manufacturer specifications of the natural gas bleed rate of each pneumatic controller installed during the compliance period. For pneumatic controllers for which the owner is claiming an exemption to the standards, the annual report would include documentation that the use of a pneumatic controller with a natural gas bleed rate greater than 6 scfh is required and the reasons why. The annual report would also include records of deviations from the applicable standards.

For pneumatic pump affected facilities, information in the annual report would include an identification of each pneumatic pump constructed, modified or reconstructed during the compliance period, as well as records of deviations in cases where the pneumatic pump was not operated in compliance with the applicable standards.

The proposed rule includes new requirements for monitoring and repairing sources of fugitive emissions at well sites and compressor stations. The owner or operator would be required to keep one or more digital photographs of each affected well site or compressor station. A photograph of every component that is surveyed during the monitoring survey is not required. The photograph must include the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file and must identify the affected facility. This could include a "still" image taken using OGI technology or a digital photograph taken of the survey being performed. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the affected facility with a photograph of a separately operating Geographic Information Systems (GIS) device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph. The owner or operator would also be required to keep a log for each affected facility. The log must include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of equipment found to have fugitive emissions, the date or dates of first attempt to repair the source of fugitive emissions, the final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired. These digital photographs and logs must be available at the affected facility or the field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely. The owner or operator would also be required to develop and maintain a corporate-wide and site specific monitoring plan enabling the fugitive emissions monitoring program.

Annual reports for each fugitive emissions affected facility would have to be submitted that include the date monitoring surveys were performed, the technology used to perform the survey, the monitoring frequency required at the time of the survey, the number and types of component found to have fugitive emissions, the date of first attempt to repair the source of fugitive emissions, the date of final repair of each source of fugitive emissions, any source of fugitive emissions found to be technically infeasible or unsafe to repair during unit operation and the date that source is scheduled to be repaired.

Consistent with the current requirements of subpart OOOO, records must be retained for 5 years and generally consist of the same information required in the initial notification and annual reports. The records may be maintained either onsite or at the nearest field office. We solicit comment on whether these records also should be sent directly to the permitting agency electronically to facilitate review remotely.

Lastly, the EPA realizes that duplicative recordkeeping and reporting requirements may exist between the NSPS, Subpart W, and other state and local rules, and is trying to minimize overlapping requirements on operators. We solicit comment on ways to minimize recordkeeping and reporting burden.

VIII. Rationale for Proposed Action for NSPS

The following sections provide our BSER analyses and the resulting proposed new source performance standards to reduce methane and VOC emissions from across the oil and natural gas source category. Our general process for evaluating BSER for the emission sources discussed below included: (1) Identification of available control measures; (2) evaluation of these measures to determine emission reductions achieved, associated costs, nonair environmental impacts, energy impacts and any limitations to their application; and (3) selection of the control techniques that represent BSER.

As mentioned previously and discussed in more detail below, the control technologies available for reducing methane and VOC emissions are the same for the emissions sources in this source category. This observation was made in the 2014 white papers and confirmed by the comments received on the 2014 white papers, as well as state regulations, including those of Colorado, that require methane and VOC mitigation measures from these sources of emissions.

CAA Section 111 also requires that EPA considers cost in determining BSER. Section VIII.A below describes how EPA evaluates the cost of control for purposes of this rulemaking. Sections VIII.B through VIII.I provide the BSER analysis and the resulting proposed standards for individual emission sources contemplated in this action.

Please note that there are minor differences in some values presented in various documents supporting this action. This is because some calculations have been performed independently *(e.g.*, TSD calculations focused on unit-level cost-effectiveness and RIA calculations focused on national impacts) and include slightly different rounding of intermediate values.

A. How does EPA evaluate control costs in this action?

Section 111 requires that EPA consider a number of factors, including cost, in determining ''the best system of emission reduction . . . adequately demonstrated.'' While section 111 requires that EPA consider cost in determining such system (*i.e.*, ''BSER''), it does not prescribe any criteria for such consideration. However, in several cases, the D.C. Circuit has shed light on how EPA is to consider cost under CAA section 111(a)(1). For example, in *Essex Chemical Corp.* v. *Ruckelshaus*, 486 F.2d 427, 433 (D.C. Cir. 1973), the D.C. Circuit stated that to be ''adequately demonstrated,'' the system must be ''reasonably reliable, reasonably efficient, and . . . reasonably expected to serve the interests of pollution control without becoming exorbitantly costly in an economic or environmental way.'' The Court has reiterated this limit in subsequent case law, including *Lignite Energy Council* v. *EPA*, 198 F.3d 930, 933 (D.C. Cir. 1999), in which it stated: ''EPA's choice will be sustained unless the environmental or economic costs of using the technology are exorbitant.'' In *Portland Cement Ass'n* v. *EPA*, 513 F.2d 506, 508 (D.C. Cir. 1975), the Court elaborated by explaining that the inquiry is whether the costs of the standard are ''greater than the industry could bear and survive.''[43] In *Sierra Club* v. *Costle*, 657 F.2d 298, 343 (D.C. Cir. 1981), the Court provided a substantially similar formulation of the cost standard when it held: ''EPA concluded that the Electric Utilities' forecasted cost was not excessive and did not make the cost of compliance with the standard unreasonable. This is a judgment call with which we are not inclined to quarrel.'' We believe that these various formulations of the cost standard—''exorbitant,'' ''greater than the industry could bear and survive,'' ''excessive,'' and ''unreasonable''—are synonymous; the DC Circuit has made no attempt to distinguish among them. For convenience, in this rulemaking, we will use reasonable to describe our evaluation of costs well within the boundaries established by this case law.

In evaluating whether the cost of a control is reasonable, EPA considers various costs associated with such control, including capital costs and operating costs, and the emission reductions that the control can achieve. A cost-effectiveness analysis is one means of evaluating whether a given control achieves emission reduction at a reasonable cost. Cost-effectiveness analysis also allows comparisons of relative costs and outcomes (effects) of two or more options. In general, cost-effectiveness is a measure of the benefit produced by resources spent. In the context of air pollution control options, cost-effectiveness typically refers to the annualized cost of implementing an air pollution control option divided by the amount of pollutant reductions realized annually. A cost-effectiveness analysis is not intended to constitute or approximate a cost-benefits analysis but rather provides a metric of the relative cost to reduction ratios of various control options.

The estimation and interpretation of cost-effectiveness values is relatively straightforward when an abatement measure controls a single pollutant. Increasingly, however, air pollution reduction programs require reductions in emissions of multiple pollutants, and in such programs multipollutant controls may be employed. Consequently, there is a need for determining cost-effectiveness for a control option across multiple pollutants (or classes of multiple pollutants). This is the case for this proposal where, for the reasons explained in section V, we are proposing to directly regulate both methane and VOC. Further, as discussed

[43] The 1977 House Committee Report noted: In the [1970] Congress [sic: Congress's] view, it was only right that the costs of applying best practicable control technology be considered by the owner of a large new source of pollution as a normal and proper expense of doing business. 1977 House Committee Report at 184. Similarly, the 1970 Senate Committee Report stated:

The implicit consideration of economic factors in determining whether technology is ''available'' should not affect the usefulness of this section. The overriding purpose of this section would be to prevent new air pollution problems, and toward that end, maximum feasible control of new sources at the time of their construction is seen by the committee as the most effective and, in the long run, the least expensive approach. S. Comm. Rep. No. 91–1196 at 16.

in more detail below, both methane and VOC are simultaneously and equi-proportionally reduced when controlled.

We have evaluated a number of approaches for considering the costs of the available multipollutant controls for reducing both methane and VOC emissions. One approach is to assign the entire annualized cost to the reduction in emissions of a single pollutant reduced by the multipollutant control option and treat the simultaneous reductions of the other pollutants as incidental or co-benefits. This was the approach we took in the 2012 NSPS but no longer believe to be appropriate for the reasons explained in section V. Under the current proposal, methane and VOCs are both directly regulated; therefore, reductions of each pollutant must be properly considered benefits, not co-benefits, and consideration of only one of the regulated pollutants is not appropriate.

Alternatively, all annualized costs can be allocated to each of the pollutant emission reductions addressed by the multipollutant control option. Unlike the approach above, no emission reduction is treated as co-benefit; each emission reduction is assessed based on the full cost of the control. However, this approach, which is often used for assessing single pollutant controls, evaluates emission reduction of each pollutant separately, assuming that each bears the entire cost, and thus inflates the control cost in the multiple of the number of additional pollutants being reduced. This type of approach therefore over-estimates the cost of obtaining emissions reductions with a multipollutant control as it does not recognize the simultaneity of the reductions achieved by the application of the control option.

Another type of approach allocates the annualized cost to the sum of the individual pollutant emission reductions addressed by the multipollutant control option. The multipollutant cost-effectiveness approach may be appropriate when each of the pollutant reductions is similar in value or impact. However, methane and VOC have quite different health and environmental impacts. Summing the pollutants to derive the denominator of the cost-effectiveness equation is inappropriate for this reason. Similarly, if the multiple pollutants could be combined with like units—for example, via economic valuation—the pollutants could be summed. We also think that this approach would be inappropriate here.

For purposes of this proposal, we have identified and are proposing to use two types of approaches for considering the cost of reducing emissions from multiple pollutants using one control. One approach assigns all costs to the emission reduction of one pollutant and zero to all other concurrent reductions; if the cost is reasonable for reducing any of the targeted emissions alone, the cost of such control is clearly reasonable for the concurrent emission reduction of all the other pollutants because they are being reduced at no additional cost. This approach acknowledges the reductions as intended as opposed to incidental or co-benefits. It also reflects the actual overall cost of the control. While this approach assigns all costs to only a portion of the emission reduction and thus may overstate the cost for that assigned portion, it does not overstate the overall cost. It also does not require evaluating in aggregate the benefits of methane and VOC emission reduction, which is not appropriate as discussed in the option immediately above. In addition, this approach is simple and straightforward in application. If the multipollutant control is cost-effective for reducing emissions of either of the targeted pollutant, it is clearly cost-effective for reducing all other targeted emissions that are being achieved simultaneously.

A second approach, which we term for the purpose of this rulemaking a ''multipollutant cost-effectiveness'' approach, apportions the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. For example, in this proposal both methane and VOC emissions are reduced in equal proportion by the multipollutant control option. As a result, half of the control costs are allocated to methane, the other half to VOC. This approach similarly does not inflate the control cost nor requires evaluating in aggregate the benefits of methane and VOC emission reduction.

We believe that both approaches discussed above are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. As such, in our analyses below, if a device is cost-effective under either of these two approaches, we find it to be cost-effective. EPA has considered similar approaches in the past when considering multiple pollutants that are controlled by a given control option.[44] The EPA recognizes, however, not all situations where multipollutant controls are applied are the same, and that other types of approaches, including those described above as inappropriate for this action, might be appropriate in other instances. The EPA solicits comments on the approaches to estimate cost-effectiveness for emissions reductions using multipollutant controls assessed in this action.

In considering control costs, the EPA takes into account any expected revenues from the sale of natural gas product that would be realized as a result of avoided emissions. Although no D.C. Circuit case addresses how to account for revenue generated from the byproducts of pollution control, or product saved as a result of control, it is logical and a reasonable interpretation of the statute that any expected revenues from the sale of recovered product may be considered when determining the overall costs of implementation of the control technology. Clearly, such a sale would offset regulatory costs and so must be included to accurately assess the costs of the standard. In our analysis we consider any natural gas that is either recovered or that is not emitted as a result of a control option as being ''saved.'' We estimate that one thousand standard cubic feet (Mcf) of natural gas is valued at $4.00.[45] Our cost analysis then applies the monetary value of the saved natural gas as an offset to the control cost. This offset applies where, in our estimation, the monetary savings of the natural gas saved can be realized by the affected facility owner or operator and not where the owner or operator does not own the gas and would not likely realize the monetary value of the natural gas saved (*e.g.*, transmission stations and storage facilities). Detailed discussions of these assumptions are presented in Chapter 3 of the RIA associated with this action, which is in the Docket.

We also completed two additional analyses to further inform our determination of whether the cost of control is reasonable, similar to compliance cost analyses we have completed for other NSPS.[46] First, we compared the capitals costs that would be incurred to comply with the

[44] See *e.g.* 73 FR 64079–64083 and EPA Document I.D. EPA–HQ–OAR–2004–0022–0622, EPA–HQ–OAR–2004–0022–0447, EPA–HQ–OAR–2004–0022–0448.

[45] The Energy Information Administration's 2014 Annual Energy Outlook forecasted wellhead prices paid to lower 48 state producers to be $4.46/Mcf in 2020 and $5.06/Mcf in 2025. The $4/Mcf price assumed in the RIA is intended to reflect the AEO estimate but simultaneously be conservatively low.

[46] For example, see our compliance cost analysis in ''Regulatory Impact Analysis (RIA) for Residential Wood Heaters NSPS Revision. Final Report.'' U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards. EPA–452/R–15–001, February 2015.

proposed standards to the industry's estimated new annual capital expenditures. This analysis allowed us to compare the capital costs that would be incurred to comply with the proposed standards to the level of new capital expenditures that the industry is incurring in the absence of the proposed standards. We then determined whether the capital costs appear reasonable in comparison to the industry's current level of capital spending. Second, we compared the annualized costs that would be incurred to comply with the standards to the industry's estimated annual revenues. This analysis allowed us to evaluate the annualized costs as a percentage of the revenues being generated by the industry.

EPA evaluated incremental capital cost in prior new source performance standards, and its determinations that the costs were reasonable were upheld by the courts. For example, the EPA estimated that the costs for the 1971 NSPS for coal-fired electric utility generating units were $19 million for a 600 MW plant, consisting of $3.6 million for particulate matter controls, $14.4 million for sulfur dioxide controls, and $1 million for nitrogen oxides controls, representing a 15.8 percent increase in capital costs above the $120 million cost of the plant. See 1972 Supplemental Statement, 37 FR 5767, 5769 (March 21, 1972). The D.C. Circuit upheld the EPA's determination that the costs associated with the final 1971 standard were reasonable, concluding that the EPA had properly taken costs into consideration. *Essex Cement* v. *EPA*, 486 F. 2d at 440. Similarly, in *Portland Cement Association*, the D.C. Circuit upheld the EPA's consideration of costs for a standard of performance that would increase capital costs by about 12 percent, although the rule was remanded due to an unrelated procedural issue. 486 F.2d at 387–88. Reviewing the EPA's final rule after remand, the court again upheld the standards and the EPA's consideration of costs, noting that ''[t]he industry has not shown inability to adjust itself in a healthy economic fashion to the end sought by the Act as represented by the standards prescribed.'' *Portland Cement* v. *Ruckelshaus*, 513 F. 2d 506, 508 (D.C. Cir. 1975). As shown below in the BSER analysis for each of the proposed standards, the associated increase in capital cost is well below the percentage increase previously upheld by the Court, and the annualized cost is but less than 1 percent of the annual revenue.

Capital expenditure data for relevant NAICS codes were obtained from the U.S. Census 2013 Annual Capital Expenditures Survey.[47] Annual revenue data for relevant NAICS codes were obtained from the U.S. Census 2012 County Business Patterns and 2012 Economic Census.[48] For both the capital expenditures and annual revenues, we obtained the Census data and performed the analyses on an affected facility basis rather than an industry-wide basis. We did this to better reflect the fact that different owners or operators are generally involved in the different industry segments. Thus, an industry-wide analysis would likely not be representative of the cost impacts on owners and operators within each segment. Although there is not a one-to-one correspondence between NAICS codes and the industry segments we used in the development of the cost impacts, we believe there is enough similarity to draw accurate conclusions from our analysis.

For the capital expenditures analysis, we determined the estimated nationwide capital costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide capital costs by the new capital expenditures (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide capital costs represent of the capital expenditures. Similarly, for the annual revenues analysis, we determined the estimated nationwide annualize costs incurred by each type of affected facility to comply with the proposed standards, then divided the nationwide annualized costs by the annual revenues (Census data) for the appropriate NAICS code(s) to determine the percentage that the nationwide annualized costs represent of annual revenues. These percentages are presented below in this section for each affected facility.

B. Proposed Standards for Centrifugal Compressors

In the 2012 NSPS, we established VOC standards for wet seal centrifugal compressors in the production segment of the oil and natural gas source category. Specifically, the standards apply to centrifugal compressors located after the well site and before transmission and storage segments because our data indicate that there are no centrifugal compressors in use at well sites.[49] In this action, we are proposing to extend these VOC standards to the remaining wet seal centrifugal compressors in the source category. We are also proposing methane standards for all wet seal centrifugal compressors in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards described above are the same as the wet seal centrifugal compressor standards currently in the NSPS.

Centrifugal compressors are used throughout the natural gas industry[50] to move natural gas along the pipeline. They are a source of methane and VOC emissions. These compressors are powered by turbines. They use a small portion of the natural gas that they compress to fuel the turbine. Sometimes an electric motor is used to turn a centrifugal compressor.

Centrifugal compressors require seals around the rotating shaft to minimize gas leakage from the point at which the shaft exits the compressor casing. There are two types of seal systems: Wet seal systems and mechanical dry seal systems.

Wet seal systems use oil, which is circulated under high pressure between three or more rings around the compressor shaft, forming a barrier to minimize compressed gas leakage. Very little gas escapes through the oil barrier, but considerable gas is absorbed by the oil. The amount of gas absorbed and entrained by the oil barrier is affected by the operating pressure of the gas being handled; higher operating pressures result in higher absorption of gas into the oil. Seal oil is purged of the absorbed and entrained gas (using heaters, flash tanks and degassing techniques) and recirculated to the seal area for reuse. Gas that is purged from the seal oil is commonly vented to the atmosphere. Degassing of the seal oil emits an average of 47.7 standard cubic feet per minute (scfm) of methane,[51] depending on the operating pressure of the compressor. Based on the average gas composition, which varies among segments of the natural gas industry, we estimate methane emission during the venting process of an uncontrolled wet seal system to be, on average, 228 tpy

[47] *http://www.census.gov/econ/aces/xls/2013/full_report.html.*

[48] For information on confidentiality protection, sampling error, and nonsampling error, see *http://www.census.gov/econ/susb/methodology.html.* For definitions of estimated receipts and other definitions, see *http://www.census.gov/econ/susb/definitions.html.*

[49] Since the 2012 NSPS, we have not received information that would change our understanding that there are no centrifugal compressors in use at well sites.

[50] See previous footnote regarding centrifugal compressors at well sites.

[51] Factors came from U.S. Environmental Protection Agency. Methodology for Estimating CH_4 and CO_2 Emissions from Natural Gas Systems. Greenhouse Gas Inventory: Emission and Sinks 1990–2012. Washington, DC. Annex 3.5. Table A–129.

in the production segment, 157 tpy in the transmission segment and 117 tpy in the storage segment. We estimate the VOC emissions to be, on average, approximately 4.34 tpy VOC in the transmission segment and 3.24 tpy of VOC in the storage segment.[52]

Dry seal systems do not use any circulating seal oil. Dry seals operate mechanically under the opposing force created by hydrodynamic grooves and springs. Fugitive emissions occur from dry seals around the compressor shaft. Based on manufacturer studies and engineering design estimates, fugitive emissions from dry seal systems are approximately 6 scfm of gas, much lower than wet seal systems. A dry seal system can have fugitive methane emissions of, on average, approximately 28.6 tpy in the processing segment, and 19.7 tpy in the transmission segment and 14.7 tpy in the storage segment. Likewise, VOC emissions are estimated to be 0.5 tpy in the transmission segment and 0.4 tpy in the storage segment.[53] In the 2012 NSPS, we did not regulate fugitive VOC emissions from dry seal compressors because we did not identify any control device suitable to capture and control such emissions. For the same reasons we explained in the 2012 NSPS, we are not proposing methane standards for dry seal compressors.

The available control techniques for reducing methane and VOC emissions from degassing of wet seal systems are the same. These include routing the gas to a process and routing the gas to a combustion device. We also consider replacing wet seal system with a dry seal system due to its inherent low emissions. These are the same options we previously identified for controlling fugitive VOC emissions from degassing of wet seal compressors. We did not find other available control options from our white paper process or information review.

During the rulemakings for the 2012 NSPS and subsequent amendments, we found that the dry seal system had inherently low VOC emissions and the option of routing to a process had at least 95 percent control efficiency. However, the integration of a centrifugal compressor into an operation may require a certain compressor size or design that is not available in a dry seal model, or in the case of capture of emissions with routing to a process, there may not be down-stream equipment capable of handling a low pressure fuel source. As such, these two options not technically feasible in all instances and, therefore, neither was the BSER for reducing fugitive VOC emissions from wet seal centrifugal compressors. Available information since then continues to show that that these two options cannot be used in all circumstances. For the same reasons, these options do not qualify as BSER for reducing methane emissions from wet seal centrifugal compressors.

In the 2012 NSPS rulemaking, we found that a capture and combustion device (option 3) had a 95 percent VOC emission reduction efficiency. Available information since then continues to support that such device can achieve 95 percent control efficiency and for both methane and VOC emissions. Based on the average uncontrolled emissions of wet seal systems discussed above and a capture and combustion device system efficiency of 95 percent, we determined that methane emissions from a wet seal system in the processing segment would be reduced by 217 tpy, by 149 tpy in the transmission segment and by 111 tpy in the storage segment. The VOC emissions would be reduced by 4.12 tpy in the transmission segment and by 3 tpy in the storage segment.[54]

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as option 3 (routing to a combustion device), is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we propose to find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, and based on an annualized cost per compressor of $114,146 to install and operate a new combustion device for the processing, transmission and storage segments, we estimate the cost of control for reducing methane emissions from a wet seal centrifugal compressor to be $478 per ton for the processing segment, $767 per ton in the transmission segment and $1,028 per ton in the storage segment. The cost of the simultaneous VOC reduction is zero because all the costs have been attributed to methane reduction.[55] It is important to note that these costs are likely over-estimates for most because they assume that each compressor requires a new, individual control device, which is not the case in most instances. It is our general understanding that multiple compressors can and do get routed to one common control. The estimates also do not reflect situations where installation of a control is not required because one is already available for use on site.

For the reasons stated above, we believe that these estimates represent a conservative scenario and that the cost of this control (routing to a combustion control device) is lower in most instances.

We also evaluate the cost of methane reduction by assigning all costs to VOC and zero to methane reduction. In the 2012 NSPS rulemaking we already found the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment. Therefore, the cost of methane reduction is reasonable for centrifugal compressors in the production segment if we assign all costs to VOC under the single pollutant approach.

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluate the cost of this control under the multipollutant approach.

Under the multipollutant approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because option 3 reduces both methane and VOC by 95 percent, we attribute 50 percent of the costs to methane reduction and 50 percent of the cost to VOC reduction. Based on this formulation, the costs for methane reduction are half of the estimated costs under the first approach above and therefore we believe these costs are reasonable for the same reasons discussed above. For VOC, we estimate the multipollutant approach costs to be $13,853 per ton in the transmission segment and $18,553 per ton in the

[52] Estimated uncontrolled VOC emissions from a wet seal compressor in the processing segment is not included here because these emissions are already subject to subpart OOOO and are not included in this proposed rule.

[53] *IBID.*

[54] Estimated VOC emissions reductions from a wet seal compressor in the processing segment is not included here because these emissions are already subject to the NSPS are not included in this proposed rule.

[55] In 2012, we already found that the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to VOC reduction from wet seal centrifugal compressors in the transmission and storage segments.

storage segment.[56] While these costs may seem high, as explained above, they are based on the assumption that a control device is required for each compressor, which is not the case in most instances. The estimates also do not reflect situations where installation of a control is not required because one is already available for use on site. For the reasons stated above, we believe the cost of VOC reduction with this control to be to lower than the above estimates in most instances. Because the operators of facilities in the transmission and storage segment typically do not own the gas they are handling, these costs do not account for gas savings in those segments. Although these reductions may not result in a direct financial benefit to the operator, we believe it is worthwhile to note that overall these standards save a non-renewable resource.

As discussed above in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital costs for complying with the proposed standards for centrifugal compressors is 0.011 percent of the total capital expenditures, which we believe is reasonable. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized costs for complying with the proposed standards is 0.001 percent of the total revenues, which we believe is reasonable.

For all types of affected facilities in the transmission and storage segment, the total capital costs for complying with the proposed standards is 0.24 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. Similarly, the total annualized costs for complying with the proposed standards is also very low, at 0.11 percent of the total revenues.

With this control option, there would be secondary air impacts from combustion. However we did not identify any nonair quality or energy impacts associated with this control technique.

In light of the above, we find that the BSER for reducing VOC emissions from wet seal centrifugal compressors in the transmission and storage segment and for reducing methane emissions from all wet seal centrifugal compressors in the oil and natural gas source category are the same, *i.e.*, to capture and route the emissions to a combustion control device. As discussed above, this option results in a 95 percent reduction of emissions for both methane and VOC.

The 2012 NSPS requires that VOC emissions from wet seal centrifugal compressors in the natural gas production segment be reduced by 95 percent, which similarly reflects the reduction that can be achieved by capturing and routing to a combustion control device. We are, therefore, proposing to extend the existing 95 percent VOC reduction standard to all other wet seal centrifugal compressors in the oil and natural gas source category (*i.e.*, natural gas transmission and storage segments). We are also proposing to require 95 percent reduction of methane emissions from all wet seal centrifugal compressors in the oil and natural gas source category. As in the 2012 NSPS, our proposal would allow dry seal systems and routing emissions to a process as alternatives to routing to a combustion device to meet the proposed 95 percent emission reduction standards. We hope that by such provisions, owners and operators would be encouraged to employ these effective emission control options where feasible. As described above, the proposed VOC and methane standards would be the same as the current VOC standards for wet seal centrifugal compressors in the NSPS.

C. Proposed Standards for Reciprocating Compressors

In the 2012 NSPS, we established VOC standards for reciprocating compressors in the production (located other than at well sites) and processing segments of the oil and natural gas source category. In this action, we are proposing VOC standards for the remaining reciprocating compressors in the source category that are not located at a well site. We are also proposing methane standards for all reciprocating compressors in the oil and natural gas source category except for those that are located at well sites.[57] Based on the analysis below, the proposed VOC and methane standards described above are the same as the reciprocating compressor standards currently in the NSPS.

Reciprocating compressors are used throughout the oil and natural gas industry and are a source of methane and VOC emissions. Emissions occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder. The most significant volumes of gas loss and resulting fugitive methane and VOC emissions are associated with piston rod packing systems. Rod packing systems are used to maintain a tight seal around the piston rod, preventing the high pressure gas in the compressor cylinder from leaking, while allowing the rod to move freely. This leakage rate is dependent on a variety of factors, including physical size of the compressor piston rod, operating speed and operating pressure. Higher leak rates are a consequence of improper fit, misalignment of the packing parts and wear. We estimate that reciprocating compressors have emissions of 0.198 tpy methane and 0.055 tpy VOC in the production segment (well sites), 12.3 tpy methane and 3.42 tpy VOC in the production segment (other than located at well site), 23.3 tpy methane and 6.48 tpy VOC in the processing segment, 27.1 tpy methane and 0.75 tpy VOC in transmission segment, and 28.2 tpy methane and 0.78 tpy VOC in the storage segment.

In developing the 2012 NSPS, we examined two options to reduce VOC emissions from reciprocating compressors. One approach was based on routing emission to a combustion device, as is used with wet seal centrifugal compressors. The other option was based on regular replacement of piston rod packing. Upon reconsideration of the standards in 2014, we evaluated a third option, routing of emissions to a process through a closed vent system under negative pressure. Information since the 2012 NSPS development have not identified other control options for reciprocating compressors.

We rejected combustion as the BSER because, as detailed in the 2011 TSD, routing of emissions to a control device can cause positive back pressure on the packing, which can cause safety issues due to gas backing up in the distance piece area and engine crankcase in some designs. While considering the option of routing of emissions to a process through a closed vent system under negative pressure, we determined that the negative pressure requirement not only ensures that all the emissions are

[56] In the 2012 rulemaking, we already concluded that the cost of this control to be reasonable for reducing VOC emissions from wet seal centrifugal compressors in the production segment and set standards for such reduction. We are not reopening that decision here. Accordingly, we are not addressing VOC reduction in the production segment here.

[57] As discussed later in this section, the control cost for reciprocating compressors at well site is not reasonable.

conveyed to the process, it also avoids the issue of inducing back pressure on the rod packing and the resultant safety concerns. Although this option can be used in some circumstances, it cannot be applied in every installation. As a result, this option was not further considered for the determination of the BSER.

As noted above, the most significant volumes of gas loss are associated with piston rod packing systems. We found that under the best conditions, new packing systems properly installed on a smooth, well-aligned shaft can be expected to leak a minimum of 11.5 scfh of natural gas. We determined that regular rod packing replacement, when carried out approximately every three years, effectively controls emissions and helps prevent excessive rod wear and determined that the BSER is regular replacement of rod packing. The control measures discussed above also reduce methane emissions.

We are not aware of any other methods for controlling methane and VOC emissions from the rod packing of reciprocating compressors. We estimate that replacement of the compressor rod packing every 26,000 hours reduces methane emissions by 0.16 tpy in the production segment (well site) 6.84 tpy in the production segment (excluding the well site), 18.6 tpy in the processing segment, 21.7 tpy in the transmission segment, and 21.8 tpy in the storage segment. Likewise, replacement of rod packing is estimated to reduce VOC emissions by 0.6 tpy in the transmission and storage segments.[58] See the 2011 TSD and 2015 TSD for details of these calculations.

For the 2012 NSPS, we estimated the annual costs of replacing the rod packing to be $2,493 for the production segment (well sites), $1,669 for the production segment (excluding well sites), $1,413 for processing plants, $1,748 for transmission stations, and $2,077 for storage facilities without considering the cost savings realized from the recovered gas. Considering gas savings, the annual cost of replacing the rod packing was $2,457 for the production segment (well sites), $83 for the production segment and a net savings for the processing segment. We did not consider gas savings for transmission and storage segments because owners and operators of these facilities do not necessarily own the gas they are handling and therefore would not realize gas savings.

As explained in section VIII.A, for purposes of this action, we have identified two approaches for evaluating whether the cost of a multipollutant control, such as rod packing replacement described above, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we propose to find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, which attributes all cost to one pollutant and zero to the other pollutant, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. When assigning all costs to methane alone and zero to the simultaneous VOC reduction, the cost of control is $15,802 per ton for the production segment (well sites), $244 per ton of methane for the production segment (excluding well sites), $76 per ton of methane for the processing segment, $81 per ton of methane in the transmission segment and $95 per ton of methane in the storage segment. When assigning all costs to VOC alone and zero to the simultaneous methane reduction, the cost of control under this approach is $2,910 per ton of VOC reduced in the transmission segment, and $3,434 per ton of VOC reduced in the storage segment.[59] In light of the above, we find the costs of rod-packing replacement are reasonable for reducing methane and VOC emissions across the industry (except at well sites) under the single pollutant approach irrespective of which pollutant bears all of the costs.

Under the multipollutant approach, because the control achieves the same reduction for both methane and VOC, we would apportion the cost equally between methane and VOC. Rod Packing replacement reduces the amount of natural gas emitted by the compressor. This natural gas contains both methane and VOC; therefore, reducing the amount of natural gas emitted will reduce methane and VOC in equal proportion. Using the multipollutant approach, the cost of control for methane is $7,901 per ton for the production segment (well sites), $122 per ton for the production segment (excluding well sites), $38 per ton for the processing segment, $40 per ton for the transmission segment, and $48 per ton for the storage segment. The cost of control for VOC under the multipollutant approach is $1,455 per ton for the transmission segment and $1,717 per ton for the storage segment.[60] In light of the above, with the exception of compressors located at well sites, we consider the costs to be reasonable for the estimated methane reductions across the source category and the estimated VOC reductions for the currently unregulated compressors under both approaches. In the 2012 NSPS rulemaking, we found the cost of rod packing not reasonable for reducing VOC emissions from reciprocating compressors at well sites. This finding remains unchanged under the two cost approaches discussed in section VIII.A. We also found the cost of control for methane emissions to not be reasonable for the amount of methane emissions achieved under either approach.

As discussed in section VIII.A, we also identified two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital costs for complying with the proposed standards for reciprocating compressors is 0.022 percent of the capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized cost for complying with the proposed standards is 0.003 percent of the total revenues, which is also very low.

For all types of affected facilities in the transmission and storage segment, the total capital cost for complying with the proposed standards is 0.24 percent of the capital expenditures, and the total annualized cost for complying with the proposed standards is also very low, at 0.11 percent of the total revenues.

We did not identify any nonair quality health or environmental impacts or energy impacts associated with replacement of rod packing and

[58] Estimated VOC emissions reductions from reciprocating compressors in the production segment (at well sites and other than well sites) and the processing segment are not included here because these emissions are already subject to the NSPS are not included in this proposed rule. Under the 2012 NSPS we found the cost of control for VOC emissions from reciprocating compressors at well sites to be unreasonable and final rule did not set standards for reciprocating compressors located at well sites.

[59] VOC emissions reductions from reciprocating compressors in the production segment (at well sites and other than well sites) and the processing segment are already subject to the 2012 NSPS. We are not reopening those standards in this action.

[60] See footnote 56.

therefore, no analyses was conducted. In light of the above, we propose that rod packing replacement is the BSER for reducing methane and VOC emissions from compressors in the oil and natural gas sector, with the exception of reciprocating compressors located at well sites. See the 2011 and 2015 TSDs, available in the docket, for detail on methodology used for emissions and cost of control estimation.

Because the VOC and methane emissions from reciprocating compressors are fugitive emissions that occur when natural gas leaks around the piston rod when pressurized natural gas is in the cylinder, it is technically infeasible capturing and routing emissions to a control device. Therefore, we are unable to set a numerical emission limit for reciprocating compressors. Pursuant to section 111(h), we are proposing an operation standard based on rod packing replacement. The proposed standards are the same as the current VOC standard in the NSPS for reciprocating compressors, which was also based on rod packing replacement. Specifically we propose to replace rod packing every 3 years of operation. However, to account for segments of the industry in which reciprocating compressors operate in pressurized mode for a fraction of the calendar year (ranging from approximately 68 percent up to approximately 90 percent), we determined that 26,000 hours of operation would be, on average, comparable to 3 years of continuous operation. As a result, we are proposing a work practice standard based on our determination that replacement of rod packing no later than after 26,000 hours of operation or after 36 calendar months represents the BSER. The owner or operator would be required to monitor the hours of operation beginning with the installation of the reciprocating compressor affected facility. Cumulative hours of operation would be reported each year in the facility's annual report. Once the hours of operation reached 26,000 hours, the owner or operator would be required to change the rod packing immediately, although unexpected shutdowns could be avoided by tracking hours of operation and planning for packing replacement at scheduled maintenance shutdowns before the hours of operation reached 26,000. Alternatively, owners and operators may replace rod packing every 36 months and would not be required to track operating hours of the compressor.

As with the current requirement for controlling VOC from these reciprocating compressors, we are allowing routing of emissions from the rod packing to a process through a closed vent system under negative pressure as an alternative to rod packing replacement. As mentioned above, it is our understanding that this technology can capture all emissions; however, it may not be applicable to every compressor installation and situation and, therefore, it would be within the operator's discretion to choose whichever option is most appropriate for the application and situation at hand.

Following the December 31, 2014, amendments to the NSPS, which added the alternative of routing of emissions from the rod packing to a process through a closed vent system under negative pressure, we received a petition for administrative reconsideration of the standard for reciprocating compressors.[61] The petitioner requested that EPA provide an additional alternative to the rod packing replacement intervals of 26,000 hours or 36 months. The alternative suggested by the petitioner would consist of monitoring of rod packing leakage to identify when the rate of rod packing leakage indicates that packing replacement is needed. We have requested additional information from the petitioner on the technical details of the petitioner's concept. As a result, we are unable at this time to evaluate the alternative suggested by the petitioner.

D. Proposed Standards for Pneumatic Controllers

In the 2012 NSPS, we established VOC standards for pneumatic controllers in the production and processing segments of the oil and natural gas source category. In this action, we are proposing VOC standards for the remaining pneumatic controllers in the source category. We are also proposing methane standards for all pneumatic controllers in the oil and natural gas source category. Based on the analysis below, the BSER for reducing the methane and VOC emissions from the pneumatic controllers described above are the same as the BSER for those that are currently subject to the VOC standards. Accordingly, the proposed VOC and methane standards described above are the same as the pneumatic controller standards currently in the NSPS.

Pneumatic controllers are automated instruments used for maintaining a process condition, such as liquid level, pressure, pressure differential and temperature that typically operate by using available high-pressure natural gas.

In these ''gas-driven'' pneumatic controllers, natural gas may be released with every valve movement or continuously from the valve control pilot. The rate at which this release occurs is referred to as the device bleed rate. Bleed rates are dependent on the design of the device. Similar designs will have similar steady-state rates when operated under similar conditions. Gas-driven pneumatic controllers are typically characterized as ''high-bleed'' or ''low-bleed,'' where a high-bleed device releases more than 6 scfh of gas. There are two basic designs: (1) continuous bleed devices (high or low-bleed) are used to modulate flow, liquid level or pressure, and gas is vented at a steady-state rate; and (2) intermittent devices perform quick control movements and only release gas when they open or close a valve or as they throttle the gas flow.[62]

Not all pneumatic controllers are gas driven. These ''non-gas driven'' pneumatic controllers use sources of power other than pressurized natural gas, such as compressed ''instrument'' air. Because these devices are not gas driven, they do not release natural gas (or methane or VOC emissions), but they do have energy impacts because electrical power is required to drive the instrument air compressor system.

As we explained for the 2012 NSPS, because manufacturers' technical specifications for pneumatic controllers are stated in terms of natural gas bleed rate rather than methane or VOC, we used natural gas as a surrogate for VOC. We evaluated the impact of a high-bleed pneumatic controller emission rate (37 scfh of natural gas for the production and processing segments and 18 scfh of natural gas for the transmission and storage segments) contrasted with the emission rate of a low-bleed unit (1.39 scfh of natural gas for the production and processing segments and 1.37 scfh of natural gas for the transmission and storage segment).[63] We determined per-controller high-bleed pneumatic controller methane emissions to be 6.91

[61] Letter from John P. Miguez, Founder and Sr. Partner, M-Squared Products & Services, Inc., to Gina McCarthy, EPA Administrator, Petition for Reconsideration, January 20, 2015.

[62] We did not address intermittent controllers in the 2012 NSPS, and we are not addressing them in this action. Intermittent controllers are inherently low emitting sources because they vent only when actuating and the total emissions are dependent on the applications in which they are used.

[63] Emission factors and emissions data for production and processing segments are from TSD for the 2011 proposed rule, available in the docket. Emission factors for transmission and storage are from Subpart W Continuous Bleed Controller Emission Factors (Table W-1A of 40 CFR Part 98, Subpart W). Available at *http://www.ecfr.gov/cgi-bin/text-idx?SID=dda4d1715e9926ee3517ac08e6258817&node=40:21.0.1.1.3.23&rgn=div6#ap40.21.98_1238.1.*

tpy in the production segment, 1 tpy in the processing segment and 3.01 tpy in the transmission and storage segment. We estimate high-bleed pneumatic controller emissions to be 0.08 tpy VOC in the transmission and storage segments.[64] In contrast, we estimate the per-controller low-bleed pneumatic controller methane emissions to be 0.26 tpy in the production segment, 1 tpy in the processing segment, and 0.23 tpy in the transmission and storage segments. We estimate the low-bleed pneumatic controller VOC emissions to be 0.006 tpy in the transmission and storage segment.

We are not aware of any add-on controls that are or can be used to reduce methane or VOC emissions from gas-driven pneumatic controllers. Therefore, the available control techniques for reducing methane and VOC emissions from pneumatic controllers are the same, which are: (1) use of a low-bleed controllers; or (2) use of non-gas driven controllers (i.e., instrument air systems). These are the same control options we previously identified in the 2012 NSPS for controlling VOC emissions from pneumatic controllers. We did not find other available control options from our white paper process or information review.

As in the 2012 NSPS, our current analysis indicates that in order to use an instrument air system, a constant reliable electrical supply would be required to run the compressors for the system. At sites without available electrical service sufficient to power an instrument air compressor, only gas driven pneumatic devices are technically feasible in all situations. Therefore, for the production and transmission and storage segments, where electrical service sufficient to power an instrument air system is likely unavailable, we evaluated only the option to use low-bleed controllers in place of high-bleed controllers.

During the development of the 2012 NSPS, we estimated methane emissions along with VOC emissions from pneumatic controllers. We estimated that for an average high-bleed pneumatic controller located in the production segment, the difference in emissions between a high-bleed controller and a low-bleed controller is 6.65 tpy methane.[65] We also estimated that replacing a natural gas-driven pneumatic controller in the processing segment with an instrument air system would reduce methane emissions by 1 tpy. Further, we estimate that the emission reductions of replacing a high-bleed with a low-bleed pneumatic controller in the transmission and storage segment would be 2.79 tpy of methane and 0.077 tpy of VOC per controller.

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as replacing a high-bleed controller with a low-bleed controller, is reasonable. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. The evaluation below for pneumatic controllers in the production, transmission and storage segments first assigns all the costs to methane reduction alone, and uses an incremental capital cost difference between a new high-bleed controller and a new low-bleed controller of $165 for the production segment and $227 for the transmission and storage segment, which results in cost of control of $24 for the production segment and $25 for the transmission and storage segment.

We estimate the cost of replacing high-bleed controllers with low-bleed controllers to be $4 per ton of methane reduced in the production segment and $9 per ton of methane reduced in the transmission and storage segment. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of simultaneous VOC reduction is zero and therefore reasonable. We also evaluated the cost by attributing all the costs to VOC reduction and estimated the cost to be $13 per ton of VOC reduction in the production segment and $323 per ton of VOC reduction in the transmission and storage segment.[66] We also find these costs to be reasonable.

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluated the cost on this control under the multipollutant approach. Under this approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because replacing a high-bleed controller with a low-bleed controller reduces the natural gas emitted by the controller, both methane and VOC are reduced equally, we attribute 50 percent of the costs to methane reduction and 50 percent of the costs to VOC reduction. Based on this formulation, the costs for methane and VOC reduction are half of the estimated costs under the first approach and are therefore reasonable.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 4862 as reported in the U.S. Census data, which we believe is representative of the transmission and storage segment. The total capital cost for complying with the proposed standards for pneumatic controllers is 0.0022 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the transmission and storage segment. The total annualized cost for complying with the proposed standards is 0.0001 percent of the total revenues, which is also very low.

For all types of affected facilities in the transmission and storage segment, the total capital costs for complying with the proposed standards is 0.24 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.11 percent of the total revenues, which is also very low.

With this option, we do not anticipate any secondary air impacts. We also did not identify any nonair quality or energy impacts associated with this control

[64] Estimated VOC emissions from pneumatic controllers in the production and processing segments are not included here because these emissions are already subject to the NSPS are not included in this proposed rule.

[65] We note that VOC emissions from pneumatic controllers in the production and processing segments are already subject to subpart OOOO. We are not reopening those standards in this rulemaking.

[66] We note that during the 2012 NSPS rulemaking, we already determined the costs of VOC reduction from pneumatic controllers at the production and processing segments to be reasonable. Accordingly, under the single-pollutant approach, the costs would also be reasonable for methane reduction as well for those pneumatic controllers.

technique, therefore, these impacts were not analyzed.

In light of the above, we find that the BSER for reducing methane emissions from continuous bleed natural gas-driven pneumatic controllers in the production and transmission and storage segment and VOC emissions from the remaining unregulated pneumatic controllers (i.e., those in the transmission and storage segment) would be the installation of low-bleed pneumatic controllers. This is the same BSER we identified in the 2012 final rule for reducing VOC emissions from pneumatic controllers in the production and processing segments.

Accordingly, we are proposing a methane emission standard for continuous-bleed, natural gas-driven pneumatic controllers in the production and transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. We are also proposing a VOC emissions standard for continuous-bleed, natural gas-driven pneumatic controllers in the transmission and storage segment to be a natural gas bleed rate of less than or equal to 6 scfh. As described above, the proposed methane and VOC standards would be the same as the current VOC standards for pneumatic controllers in the production segment in the NSPS.

It is important to note that these costs are most likely over-estimates because they do not take into account the cost savings that would result based on the value of natural gas saved. Therefore, the above cost estimated, which we have already found to be reasonable, represent a conservative scenario and that the cost of these controls are lower in most instances.

For the processing segment, which comprises pneumatic controllers at natural gas processing plants, we identified instrument air systems and replacement of high-bleed controllers with low-bleed controllers as control options for reducing methane emissions from pneumatic controllers.[67] These are the same options we identified for the 2012 rule to reduce VOC emissions from these pneumatic controllers. As described below, we first evaluated the cost of an instrument air system to reduce methane emissions. Since we found these costs to be reasonable (as discussed below), we did not evaluate the costs of replacing the high-bleed pneumatic controllers with low-bleed controllers because the replacement option would result in less methane emission reduction than the instrument air option.

The annual costs of the instrument air system per gas processing plant without considering the cost savings realized from the recovered gas are $11,090, and $7,676 when considering these savings. See the 2012 Supplemental TSD[68] for details of these calculations.

We evaluate the cost of using an instrument air system to reduce methane emissions from the pneumatic controllers at gas processing plants based on the two approaches identified earlier in this section for considering the cost of a multipollutant control (in this case the instrument air system). Under the single pollutant approach, which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. In the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). Having assigned all the cost to VOC, the cost of methane reduction would be zero and therefore clearly reasonable. If we assign all the cost to methane instead, it is $738 per ton without considering cost savings and $506 per ton considering cost savings. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear. In light of the above, we find the cost of reducing methane emissions from the pneumatic controllers at gas processing plants to be reasonable under the single pollutant approach.

The second approach is to evaluate the cost on a multipollutant basis, based on the percentage reduction expected of VOC and methane. We estimate that replacing high-bleed pneumatic controllers with a non-natural gas driven pneumatic controller (i.e., instrument air-powered) reduces methane emissions by 15 tpy and VOC emissions by 4.2 tpy at gas processing plants. Refer to the 2012 TSD for details of these calculations. Because the control achieves the same reduction for both methane and VOC, under this approach, we apportion the cost equally, resulting in a cost of control of $369 per ton of methane reduced without considering gas savings. Considering gas savings, the cost of control is $253 per ton of methane. These costs do not appear excessive, nor do we have reason to believe that they are beyond what the industry can bear.

With respect to the VOC control cost under this approach, as mentioned above, in the 2012 NSPS rulemaking, we already determined that the cost of this control for reducing VOC emissions alone is reasonable for pneumatic controllers at gas processing plants (76 FR 52760). The cost of VOC reduction under the multiple pollutant approach would be half of that cost and therefore clearly reasonable. In light of the above, we find the cost of reducing methane emissions from pneumatic controllers at gas processing plants to be reasonable as well under the multi-pollutant approach. As mentioned above, we did not identify any nonair quality or energy impacts associated with this control option, therefore no impacts were analyzed.

Based on the above considerations, we propose that pneumatic controllers powered by an instrument air system are the BSER for reducing methane emission from pneumatic controllers at gas processing plants. This is the same BSER we identified for reducing VOC emissions from pneumatic controllers at gas processing plants in the 2012 final rule.

For the reasons discussed above and in the TSD, we have determined that BSER for reducing methane emissions from pneumatic controllers in the processing segment to be instrument air-activated controllers which represent an emission rate of zero for methane. Accordingly, we are proposing a methane standard for pneumatic controllers in the processing segment to be a natural gas bleed rate of zero. This is the same as the VOC standard for these pneumatic controllers in the 2012 NSPS.

We have identified situations where high-bleed controllers are necessary due to functional requirements, such as positive actuation or rapid actuation. An example would be controllers used on large emergency shutdown valves on pipelines entering or exiting compression stations. The current NSPS takes this into account by exempting pneumatic controllers from meeting the applicable emission standards if compliance would pose a functional limitation due to their actuation response time or other operating characteristics. We propose to similarly exempt pneumatic controllers from meeting the proposed methane standard if compliance would pose a functional limitation due to their actuation response time or other operating characteristics.

[67] In the 2012 NSPS, EPA established VOC standards for pneumatic controllers at natural gas processing plants. We are not reopening up those standards in this proposed rule.

[68] Oil and Natural Gas Section: Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution—Background Supplemental Technical Support Document for the Final New Source Performance Standards, USEPA, Office of Air Quality Planning and Standards, April 2012.

E. Proposed Standards for Pneumatic Pumps

In the 2012 NSPS, we did not establish standards for pneumatic pumps. Pneumatic pumps are devices that use gas pressure to drive a fluid by raising or reducing the pressure of the fluid by means of a positive displacement, a piston or set of rotating impellers. Gas powered pneumatic pumps are generally used at oil and natural gas production sites where electricity is not readily available and can be a significant source of methane and VOC emissions.[69] As discussed previously, in April 2014, the EPA published a white paper titled ''Oil and Natural Gas Sector Pneumatic Devices.'' The paper summarized the EPA's understanding of methane and VOC emissions from pneumatic pumps and also presented the EPA's understanding of mitigation techniques (practices and equipment) available to reduce these emissions, including the efficacy and cost of the technologies and the prevalence of use in the industry.

During our review of the public and peer review comments on the white paper and the Wyoming state rules, we identified different types of pneumatic pumps that are commonly used in the oil and natural gas sector. Wyoming is the only state of which we are aware that has air emission standards for pneumatic pumps. Pneumatic chemical and methanol injection pumps are generally used to pump fairly small volumes of chemicals or methanol into well-bores, surface equipment, and pipelines. Typically, these pumps include plunger pumps with a diaphragm or large piston on the gas end and a smaller piston on the liquid end to enable a high discharge pressure with a varied but much lower pneumatic supply gas pressure. They are typically used semi-continuously with some seasonal variation. Pneumatic diaphragm pumps are another type used widely in the oil and natural gas sector to move larger volumes of liquids per unit of time at lower discharge pressures than chemical and methanol injection pumps. The usage of these pumps is episodic including transferring bulk liquids such as motor oil, pumping out sumps, and circulation of heat trace medium at well sites in cold climates during winter months.

Emissions from pneumatic pumps occur when the gas used in the pump stroke is exhausted to enable liquid filling of the liquid chamber side of the diaphragm. Emissions are a function of the amount of fluid pumped, the pressure of the pneumatic supply gas, the number of pressure ratios between the pneumatic supply gas pressure and the fluid discharge pressure, and the mechanical inefficiency of the pump.

Based on emission factors obtained from an EPA/GRI report[70] we estimate emissions from natural gas-driven piston pumps (i.e., pneumatic chemical and methanol injection pumps) and diaphragm pumps in both the production and processing segments to be 2.48 scf natural gas per hour and 22.45 scf natural gas per hour respectively. Based on these emission rates, and using the gas composition developed during the 2012 NSPS for the production and processing segments (i.e., natural gas is 82.9 percent methane and VOC constitutes 0.27797 pounds of VOC per pound of methane), we estimate the baseline emissions from a natural gas-driven piston pump in either the production or processing segment to be 0.38 tpy of methane and 0.11 tpy of VOC, and a gas-driven diaphragm pump to be 3.46 tpy of methane and 0.96 tpy of VOC.

We estimate that emissions in the transmission and storage segment are 2.21 scf natural gas per hour for a pneumatic piston pump and 20.05 scf natural gas per hour for a diaphragm pump. Based on these emissions rates, and using the gas composition developed during the 2012 NSPS for the transmission and storage segment (i.e., natural gas is 92.8 percent methane and VOC constitutes 0.0277 pounds of VOC per pound of methane), we estimate the baseline emissions from a natural gas-driven piston pump to be 0.38 tpy of methane and 0.01 tpy of VOC, and a gas-driven diaphragm pump to be 3.46 tpy of methane and 0.10 tpy of VOC in the transmission and storage segment. These emission estimates are explained in detail in the TSD for this action available in the docket.

As discussed in the white paper, we identified several options for reducing methane and VOC emissions from natural gas-driven pumps: replace natural gas-driven pumps with instrument air pumps, replace natural gas-driven pumps with solar-powered direct current pumps (solar pumps), replace natural gas-driven pumps with electric pumps, and route natural gas-driven pump emissions to a control device. In some applications, chemical injection pumps can be retrofitted with instrument air to drive the pumps.[71] During our review of the Wyoming state rule covering pneumatic pumps, we identified an additional mitigation option for reducing emission from piston and diaphragm natural gas-driven pumps, which involves routing the gas to a process[72] or routing the gas to a combustor (often done as part of the storage vessel control system). As with the BSER for wet seal centrifugal compressors discussed earlier in this section, the emission reduction potential for this option is estimated at 95 percent based on the efficiencies of the capture system and the combustion device. No further control options were identified from our white paper process or information review.

Instrument air systems and electric pumps require a reliable, constant supply of electrical power. Because of their remote locations, well sites, gathering and boosting stations and potentially transmission stations and storage facilities may not necessarily have a constant, reliable electrical power supply. Therefore, we do not believe the use of instrument air systems and electric pumps are feasible at all facilities in the production and transmission and storage segments. However, we take comment on is the availability of a constant, reliable source of electrical power at facilities throughout the oil and natural gas source category.

Natural gas processing plants are known to have a constant and reliable source of electrical power. Therefore, instrument air systems are technically feasible at natural gas processing plants. Because pumps powered by instrument air systems release no natural gas, the methane and VOC emissions are reduced by 100 percent under this control option.

For natural gas processing plants, the potential emission reduction for the instrument air option is 3.46 tpy of methane and 0.96 tpy of VOC for each diaphragm pump, and 0.38 tpy of methane and 0.11 tpy of VOC for each piston pump replaced.

While solar pumps can be installed in certain situations, these pumps are not technically feasible in all situations for which piston pumps and diaphragm pumps are needed. Specifically, weather

[69] GRI/EPA, 1996d.

[70] EPA/GRI. Methane Emissions from the Natural Gas Industry, Volume 13: Chemical Injection Pumps. June 1996 (EPA–60/R –96– 80m), Sections 5.1—Diaphragm Pumps and 5.2—Piston Pumps.

[71] U.S. EPA, 2011b.

[72] Subpart OOOOa defines ''route to a process'' to mean that ''the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.''

conditions in certain areas can limit the effectiveness of solar pumps and the capacity of solar pumps is also limited, so they cannot be used in all situations where larger pumps are needed. Therefore, solar pumps are not universally feasible control option for the production and transmission and storage segments.

As a result, we further analyzed the remaining potential control option for the production and transmission and storage segments, which is routing of natural gas-driven pump emissions to a process (e.g., used as fuel for a combustion source) or control device. Assuming that emissions are routed through a closed vent system to a control device or process, we believe these control options achieve a 95 percent reduction in emissions of methane and VOC.

Based on a 95 percent reduction, we estimate the reduction in emissions in the production segment to be 0.36 tpy methane and 0.10 tpy VOC per piston pump and 3.29 tpy of methane and 0.91 tpy of VOC per diaphragm pump. In the transmission and storage segment, we estimate the reduction in emissions to be 0.36 tpy of methane and 0.01 tpy VOC per piston pump and 3.29 tpy of methane and 0.09 tpy of VOC per diaphragm pump.

For purposes of this action, we have identified in section VIII.A two approaches for evaluating whether the cost of a multipollutant control, such as routing emissions to a combustion device, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. In the evaluation below, we assign all the costs to methane reduction alone and then to VOC reduction alone. For installing a new control device in the production segment we estimate the cost of control for reducing methane emissions using a combustion device to be $60,602 per ton for piston pumps and $6,656 per ton for diaphragm pumps. The cost of control for reducing VOC emissions for the production segment is $218,017 per ton for piston pumps and $23,944 for diaphragm pumps. For both the transmission and storage segment we estimate the cost of control for reducing methane emissions using a new combustion device to be $60,602 per ton for piston pumps and $6,656 per ton for diaphragm pumps. The cost of control for reducing VOC emissions for both the transmission and storage segment is $2,187,805 per ton for piston pumps and $240,279 for diaphragm pumps. We do not consider these cost to be reasonable.

Under the multipollutant approach we attributed half the cost to the methane reduction and half to the VOC reduction. For the production segment, we estimate the cost of reducing methane emissions using a new combustion device for piston pumps to be $30,301 per ton and the cost of reducing VOC emissions to be $109,009 per ton. For diaphragm pumps, the cost of reducing methane emissions is $3,328 per ton and the cost of reducing VOC emissions is $11,972 per ton. For both the transmission and storage segment, we estimate the cost of reducing methane emissions for piston pumps to be $30,301 per ton and the cost of reducing VOC emissions to be $1,093,903 per ton. For diaphragm pumps, the cost of reducing methane emissions is $3,328 per ton and the cost of reducing VOC emissions is $120,140 per ton. We also do not consider these cost to be reasonable.

While the use of a new combustion device is not cost-effective, the costs appear reasonable when using an existing combustion control device that is already on site. For routing the emissions in the production segment to an existing combustion control device, under the single pollutant approach, if we assign all costs to reducing methane emissions and zero to VOC reduction, the cost is $789 per ton of methane reduced for piston pumps and $87 per ton of methane reduced for diaphragm pumps.[73] If we assign all costs to VOC reduction and zero to methane reduction, the cost of reducing VOC emissions using an existing combustion control device in the production segment is $2,840 for piston pumps and $312 for diaphragm pumps. For both the transmission and storage segment, if we assign all costs to methane reduction and zero to VOC reduction, the cost of reducing methane emissions is $789 per ton for piston pumps and $87 per ton for diaphragm pumps.[74] If we assign all costs to VOC reduction and zero to methane reduction, the cost of reducing VOC emissions in the transmission and storage segment is $28,501 for piston pumps and $3,130 for diaphragm pumps. As shown above, under the single pollutant approach (i.e., all costs are assigned to one pollutant and zero to the other), the costs are reasonable regardless of which pollutant bears all the costs, except for the piston pump at the transmission and storage segment if all costs are assigned to VOC. In that case, while the cost is high if it is all assigned to VOC reduction, the cost is reasonable when assigned to methane reduction.

We also evaluated the cost of control for routing emissions to an existing control device under the multipollutant approach. For the production segment, we estimate the cost of reducing methane emissions for piston pumps to be $395 per ton and the cost of reducing VOC emissions to be $1,420 per ton. For diaphragm pumps, the cost of reducing methane emissions is $43 per ton and the cost of reducing VOC emissions is $156 per ton. For both the transmission and storage segment, we estimate the cost of reducing methane emissions for piston pumps to be $395 per ton and the cost of reducing VOC emissions to be $14,250 per ton. For diaphragm pumps, the cost of reducing methane emissions is $43 per ton and the cost of reducing VOC emissions is $1,565 per ton. With respect to piston pumps at transmission and storage segments, we note that the control is cost-effective under the single pollutant approach.

We further evaluated the cost of control for routing the emissions to a process by installing a new VRU or utilizing an existing VRU and found these costs to be similar to the costs presented above for new and existing combustion devices, respectively. We determined that the cost of control for routing to a process is similar to the costs presented above for an existing combustion device (see the TSD for this action for details of this analysis).

The option of routing emissions to a control device would result in secondary impacts from combustion. However, we did not identify any nonair quality or energy impacts associated with this option.

For natural gas processing plants, we evaluated instrument air systems based on a 100 percent emissions reduction potential resulting in a natural gas emission rate of zero standard cubic feet per hour. We estimated the potential reduction in emissions to be 0.38 tpy of methane and 0.11 tpy of VOCs per piston pump and 3.46 tpy of methane and 0.96 tpy of VOC per diaphragm pump.

Because instrument air systems are known to be used at natural gas

[73] This is well below the amount we find reasonable for reducing fugitive methane emissions at well site (see Section VIII.G.1 below).

[74] This is well below the amount we find reasonable for reducing fugitive methane emissions at well site (see Section VIII.G.1 below).

processing plants, we evaluated this option based on the incremental additional cost of routing the natural gas-driven pumps to an existing instrument air system, assuming all natural gas processing plants currently use instrument air systems. We determined that the incremental cost would be the cost of aligning the capacity of the existing instrument air system to that needed after the addition of the pumps. We determined that the facility would likely either replace an existing compressor or add a compressor to address any needed additional capacity. Because we do not have data on the number and distribution of types of natural gas-driven pumps at a typical natural gas processing plant, we developed several model plant scenarios. We varied the size of the plant (i.e., the total number of natural gas-driven pumps) from small, consisting of 4 natural gas-driven pumps per plant to large, consisting of 100 natural gas-driven pumps per plant. We also, within the size of the plant, varied the distribution of the type of pumps using three distribution scenarios (i.e., 50 percent diaphragm and 50 percent piston, 25 percent diaphragm and 75 percent piston, and 75 percent diaphragm and 25 percent piston). For each model plant, we evaluated the cost of an appropriately sized compressor based on the required additional capacity needed by number and types of pumps. Details of this analysis are included in the TSD for this action.

Under the single pollutant approach, which assigns all costs to the reduction of one pollutant and zero to all other pollutants, the cost of control for the model plants ranges from $374 to $2,185 per ton of methane reduced when assigning all costs to alone to methane reduction, and ranges from $1,344 to $7,861 per ton of VOC reduced when assigning all the costs alone to VOC reduction.

Under the multipollutant approach, we assigned half the cost of control to the methane reduction and half the cost to the VOC reduction. The cost of control under the second approach for the model plants ranges from $187 to $1,093 per ton of methane reduced and $672 and $3,930 per ton of VOC reduced. We find the control to be cost-effective under either approach.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital cost for complying with the proposed standards for pneumatic pumps is 0.02 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII. A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.001 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

In light of the above, we find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps in the production and transmission and storage segments to be the same, which is to route the emissions to an existing control device or route the emissions to a process. As discussed above, this option results in a 95 percent reduction of emissions for both methane and VOC.

We find that the BSER for reducing methane and VOC emissions from natural gas-driven piston and diaphragm pumps at gas processing plants is to use an instrument air system in place of natural gas to drive the pumps. This option results in a 100 percent reduction of emissions for both methane and VOC.

We are, therefore, proposing to require 95 percent methane and VOC control from all natural gas-driven pneumatic pumps in the production and transmission and storage segments. For gas processing plants, we are proposing to require 100 percent methane and VOC control from all pneumatic pumps.

As discussed above in this section, solar-powered, electrically-powered and air-driven pumps cannot be employed in all applications. However, we encourage operators to use other than natural gas-driven pneumatic pumps where their use is technically feasible. To incentivize the use of such alternatives, we propose that ''pneumatic pump affected facility'' be defined in § 60.5365(h) to include only natural gas-driven pumps. As a result, pumps which are driven by means other than natural gas would not be affected facilities subject to the pneumatic pump provisions of the proposed NSPS.

Public and peer review comments on the white paper noted that, in addition to piston injection pumps and diaphragm pumps, gas assist glycol dehydrator pumps are used to pump lean glycol through glycol dehydrator systems. The glycol dehydrator pumps tend to be more complex because they ''scavenge'' energy from the high pressure (rich) glycol flowing from the contactor to the regenerator to provide the bulk of the energy needed to pump the lean glycol into the contactor. These types of pumps are used continuously when the glycol dehydrator is in use. Emissions from gas assist pumps are a function of the lean glycol circulation rate, the pressure of the contactor, and the model of the pump. Commenters of the white paper indicate that the emissions profile of all three types of pumps are very different. Commenters note that data for the EPA/GRI report for gas assisted glycol pumps is calculated based on two assumptions of process conditions, water removal, and information from the pump manufacturer which result in significant limitations for the calculated emission factor derived in the report. Furthermore, commenters discuss the NEI have activity factors and emissions separated from the glycol process emissions for gas assist lean glycol pumps, however commenters believe that it is not clear whether the estimate is valid.[75] Our understanding is that emissions from glycol dehydrator pumps are not separately quantified because these emissions are released from the same stack as the rest of the emissions from the dehydrator system, which are regulated under the NESHAP at 40 CFR part 63 HH and HHH. It is also our understanding from commenters that replacing the natural gas in gas-assisted lean glycol pumps with instrument air is not feasible and would create significant safety concerns. Commenters state that the only option for these types of pumps are to replace them with electric motor driven pumps however, solar and battery systems large enough to power these types of pumps are not feasible. The EPA is requesting comment and additional information on the level of uncontrolled emissions from these pumps, how these pumps are vented through the dehydrator system, and the amount and characteristics of VOC and methane emissions from uncontrolled glycol dehydrators.

[75] June 13, 2014, API comments on EPA's white paper on oil and natural gas sector pneumatic devices.

F. Proposed Standards for Well Completions

For the 2012 NSPS and this action, we have identified two subcategories of hydraulically fractured wells: (1) Non-exploratory and non-delineation wells, also known as development wells; and (2) exploratory (also known as wildcat wells) and delineation wells. An exploratory well is the first well drilled to determine the presence of a producing reservoir and the well's commercial viability. A delineation well is a well drilled to determine the boundary of a field or producing reservoir. In the 2012 NSPS analysis, we determined that the emissions profile for subcategory 2 wells is the same as subcategory 1 wells as described above. In our review of white paper comments and other information for this action, we found no information that would indicate this conclusion is not still valid.

1. Proposed Standards for Hydraulically Fractured Non-Wildcat and Non-Delineation Wells (Subcategory 1 Wells)

In the 2012 NSPS, we established VOC standards for subcategory 1 hydraulically fractured gas well completions and recompletions in the oil and natural gas source category. In this action, we are proposing VOC standards for subcategory 1 oil well completions and recompletions and methane standards for all subcategory 1 well completions and recompletions in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards are the same as the gas well completion standards currently in the NSPS.

As explained in the 2012 NSPS, well completions with hydraulic fracturing are a significant source of VOC and methane emissions, which occur when natural gas and non-methane hydrocarbons are vented to the atmosphere during flowback of a hydraulically fractured well. Flowback emissions are short-term in nature and occur over a period of several days following fracturing or refracturing of a well. Well completions include multiple steps after the well bore hole has reached the target depth. These steps include inserting and cementing-in well casing, perforating the casing at one or more producing horizons, and often hydraulically fracturing one or more zones in the reservoir to stimulate production. Hydraulic fracturing is one technique for improving oil or gas production where the reservoir rock is fractured with very high pressure fluid, typically water emulsion with a proppant (generally sand) that ''props open'' the fractures after fluid pressure is reduced. Emissions are a result of the flowback of the fracture fluids and reservoir gas at high volume and velocity necessary to lift excess proppant and fluids to the surface. This multi-phase mixture is often directed to a surface impoundment or to vented tanks (''frac tanks''), where methane and VOC vapors escape to the atmosphere during the collection of water, sand and hydrocarbon liquids. For oil wells, as the fracture fluids are depleted, the flowback eventually contains more volume of crude oil from the formation.

Wells that are fractured generally have greater amounts of VOC and methane emissions than conventional wells because of the extended length of the flowback period required to purge the well of the fluids and sand that are associated with the fracturing operation. Along with the fluids and sand from the fracturing operation, the flowback period may also result in emissions of methane and VOC that would not occur in large quantities at wells that are not fractured.

There are a variety of factors that will determine the length of the flowback period and actual volume of emissions from a well completion such as the number of zones, depth, pressure of the reservoir, gas composition, etc. This variability means there will be variability in the emissions from well completions.

For the 2012 NSPS, we estimated that the emissions from an uncontrolled gas well completion were 155.5 ton of methane and 22.7 tons of VOC per completion event. We also evaluated oil well completions emissions for the 2012 NSPS; however, based on that evaluation, we found oil well completion emissions to be very low and, therefore, no standard was set for oil well completions.

For this action, we reviewed new emissions studies and information for oil well completions, as described in the 2014 white paper titled ''Oil and Natural Gas Sector Hydraulically Fractured Oil Well Completions and Associated Gas during Ongoing Production.'' [76] While there was a wide variation in the results of these studies and analyses, even in the lowest estimates the potential methane and VOC emissions from hydraulically fractured oil well completions were significant. This conclusion is consistent with the Federal Implementation Plan (FIP) for the Fort Berthold Indian Reservation (FBIR) (78 FR 17836), in which the EPA found that the emissions from oil well completions are significant. One difference identified in our review of comments from the 2014 white paper process was that the average duration of an oil well completion is on the lower end of the duration identified in our 2012 analysis, or 3 days. Therefore, for this action, based on our review of these estimates and the methodologies used and in consideration of these comments, we estimate the potential emissions from hydraulically fractured oil well completions to be 9.72 tons methane and 8.14 tons VOC per 3-day completion event. These estimates are explained in detail in the 2012 TSD and the TSD for this action which are both available in the docket.

For the 2012 NSPS, we evaluated three options for reducing methane and VOC emissions from hydraulically fractured well completions: RECs, combustion (*e.g.,* flaring), and the combination of REC with combustion. For this action, we reviewed public and peer comments on the white paper as well as state (*i.e.,* Colorado [77] and Wyoming [78]) and other federal regulations (*i.e.,* FBIR FIP). We found that the available control techniques for reducing methane and VOC emissions from well completion are the same, and they were the same as the control options we previously identified for controlling VOC emissions: use of a REC, combustion, and the combination of REC with combustion. We did not find any other available control options from our white paper process or information review.

RECs are performed by separating the flowback water, sand, hydrocarbon condensate and natural gas to reduce the portion of natural gas and VOC vented to the atmosphere, while maximizing recovery of salable natural gas and condensate and routing the salable gas to a sales line and routing the recovered condensate to a completion or storage vessel for collection. Equipment required to conduct RECs may include tankage (*e.g.,* ''frac tanks''), special gas-liquid-sand separator traps and gas dehydration.

Control by combustion is achieved through the use of a completion combustion device. Based on our review, we believe that traditional combustion control devices, (*i.e.,* flares

[76] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415completions.pdf.*

[77] Colorado Oil and Gas Conservation Commission (COGCC) 805 Series Rules (805.b.(3)A) at: *http://cogcc.state.co.us/* and the Colorado Code of Regulations at: *http://www.sos.state.co.us/CCR/Welcome.do.*

[78] WY BACT permitting guidance available at *http://deq.state.wy.us/aqd/Oil%20and%20Gas/September%202013%20FINAL_Oil%20and%20Gas%20Revision_UGRB.pdf.*

or enclosed combustion control devices), are infeasible for use on completion emissions because the flowback following hydraulic fracturing consists of liquids, gases and sand in a high-volume, multiphase slug flow.

We evaluated RECs, completion combustion devices and the combination of RECs with completion combustion devices in order to determine the BSER for subcategory 1 wells. See the 2012 TSD and the TSD for this action, available in the docket, for further details on this evaluation. Our evaluation indicates that REC alone provides for a 90 percent control of emissions where gas emitted from the well is of suitable quality to be routed to a gathering line. However, in some cases, the initial gas produced from the well does not meet quality specifications for entering gathering lines, and as a result, the gas must be either vented or combusted. Due to the potential for gas to be emitted, even during the use of a REC, we determined that the use of a REC alone, would not be the BSER for control of emissions from well completions. Our evaluation of REC combined with a completion combustion device indicated that this option resulted in a 95 percent control of both methane and VOC emissions. We believe this option maximizes gas recovery and minimizes venting to the atmosphere.

Under the last option, combustion, we determined that a completion combustion device would achieve a 95 percent reduction in both methane and VOC emissions. However, we determined that combustion alone would not represent the BSER for well completions because, although the emissions reduction would be equal to the REC and completion combustion device combination (*i.e.,* 95 percent control), the opportunity to realize gas recovery would be minimized and the generation of secondary combustion-related emissions would be increased.

Based on the 95 percent emission reduction of a REC combined with a combustion device, in the 2012 NSPS, the emission reductions for a hydraulically fractured gas well completion event were estimated to be 147.4 tons of methane per completion.[79] In this analysis, we estimate the emission reductions for a hydraulically fractured oil well completion event to be 9.23 tons of methane and 7.73 tons of VOC per completion based on a 3-day completion event.

Equipment costs associated with RECs will vary from well to well. Costs of performing REC are projected to be between $700 and $6,500 per day, varying based on if key pieces of equipment are readily available on site or temporarily brought on site. Based on the 2012 NSPS evaluation, the average cost of a REC combined with completion combustion device for a 7-day completion event was $33,327. Under our evaluation in this action, we estimate the cost for a REC combined with a completion combustion device for a 3-day completion event to be $17,183. However, in both cases, there are savings associated with the use of RECs because the gas recovered can be incorporated into the production stream and sold. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 7-day completions event for a gas well was estimated to have a net savings. With the consideration of gas savings, the cost of a REC combined with a completion combustion device for a 3-day completions event for an oil well was estimated to be $13,586.

We determined that the completion combustion device option for well completions also reduces both methane and VOC emissions by 95 percent. Therefore, the emissions reductions would be the same as those cited above for the REC combined with a completion combustion device. The annual cost for a completion combustion device alone was estimated be $3,523 for the 2012 NSPS for gas wells and $3,723 under this action for oil wells.

For purposes of this action, we have identified in section VIII.A two approaches (single pollutant approach and multipollutant approach) for evaluating whether the cost of a multipollutant control is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, and based on an average cost of $33,327 per completion event for a gas well,[80] a REC combined with a completion combustion device, would cost $226 per ton of methane reduced per gas well completion without cost savings.[81] As noted above, this option maximizes gas recovery and minimizes venting to the atmosphere. Thus, when the value of the natural gas recovered (approximately 1,609 Mcf of natural gas) is considered, there is a net savings realized for this option for a subcategory 1 gas well completion or recompletion. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of the simultaneous VOC reduction is zero and therefore reasonable. Based on the $17,183 annual cost of a REC combined with a completion combustion device for a 3-day completion event for an oil well completion, with the cost attributed only to methane and zero cost attributed to VOC, the cost of control would be $1,861 per ton of methane reduced per oil well completion without considering cost savings attributable to recovery of natural gas. As noted above, this option maximizes gas recovery and minimizes venting to the atmosphere. Thus, when the value of the natural gas recovered (approximately 999 Mcf of natural gas) is considered, the cost of control would be $1,471 per ton of methane reduced. Under this approach, the cost of control with all cost attributed to VOC would be $2,222 per ton of VOC reduced without considering natural gas savings and $1,757 with savings realized from natural gas recovery. Although the cost of control for a 3-day completion event at an oil well is higher than the cost at a gas well, we believe that the emissions reductions collectively are significant to justify the cost. Furthermore, we believe that the industry can bear the cost and survive.

Under the multipollutant approach, we assign 50 percent of the cost to methane and 50 percent to VOC. The cost of a REC with completion combustion for a gas well under this approach would be $930 per ton of methane and $1,111 per ton of VOC reduced without considering natural gas savings. With consideration of natural gas savings, the cost of control is $736 per ton of methane and $879 per ton of VOC reduced. Based on this

[79] Emissions of VOC from hydraulically fractured subcategory 1 gas wells are subject to the current NSPS and are not included in this action.

[80] As was determined for the 2012 NSPS.

[81] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from subcategory 1 gas well completions and recompletions. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to methane reduction from subcategory 1 hydraulically fractured gas well completions.

formulation, the costs for pollutant reduction are half of the estimated costs under the single pollutant approach above and therefore we believe these costs are not excessive for the same reasons discussed above.

Under the single pollutant approach, based on the $3,723 annual cost of a completion combustion device alone, with the cost attributed only to methane and zero attributed to VOC, the cost of control would be $403 per ton of methane reduced per oil well completion. Under this approach, the cost of control with cost attributed to VOC would be $481 per ton of VOC reduced. Under the multipollutant approach, we assign 50 percent of the cost to methane and 50 percent to VOC. The cost of control under this approach would be $202 per ton of methane and $241 per ton of VOC reduced. We think that these costs are reasonable.

See the TSD, available in the docket for this action, for a detailed description of the cost of control analysis.

We believe that the cost for both options, a REC combined with combustion and combustion alone, are reasonable, given the emission reduction that would be achieved. However, given that the reductions in emissions are equal between the two control options, the REC combined with combustion option provides a better environmental benefit with the recovery of natural gas and reduced secondary combustion-related emissions. Aside from the potential hazards (in some cases) associated with combustion devices, we did not identify any nonair environmental impacts, health or energy impacts associated with REC combined with combustion, therefore these impacts were not analyzed.

The use of a completion combustion device with this option would produce secondary impacts in the form of combustion-related emissions. We estimate that, for subcategory 1 oil wells completed using a combination of REC and combustion for the year 2020, the combustion control-related emissions would be approximately 26 tons of total hydrocarbons, 69 tons of carbon monoxide, 24,846 tons of carbon dioxide, and 13 tons of nitrogen oxides.[82] This is based on the assumption that 5 percent of the flowback gas is combusted for subcategory 1 oil wells (controlled with a REC combined with a completion combustion device).

We estimate that this option of control for subcategory 1 oil well completions, for the projected year 2020, will result in estimated emission reductions of 127,478 tons of methane and 106,750 tons of VOC. Thus, we believe that the benefit of the methane and VOC reductions far outweigh the secondary impacts of combustion emissions formation during use of the completion combustion operation. Further, should only combustion be considered for all oil well completions, including the subcategory 1 wells, the secondary impacts would be far greater than those shown above. Secondary impacts of combustion alone are presented in the discussion of subcategory 2 wells below in this section.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital costs for complying with the proposed standards for subcategory 1 wells is 0.081 percent of the total capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.033 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we determine the BSER for subcategory 1 (developmental wells) is the combination of REC and the use of a completion combustion device. We considered setting a numerical performance standard; however, we determined that it is not feasible to prescribe or enforce a numerical performance standard in this case because the gas can be discharged at multiple locations along with water and sand in a multiphase slug flow during the flowback process and, therefore, may not always be emitted at the same specific location in the process or through one conveyance designed and constructed to emit or capture such pollutant. Therefore, pursuant to section 111(h)(2) of the CAA, we are proposing an operational standard for subcategory 1 wells that would require a combination of gas capture and recovery and completion combustion devices to minimize venting of gas and condensate vapors to the atmosphere, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards or for periods when the flowback gas is noncombustible.

For the purposes of these standards we have separated the flowback period into two stages, the ''initial flowback stage'' and the ''separation flowback stage.'' The initial flowback stage begins with the first flowback from the well following hydraulic fracturing or refracturing and is characterized by high volumetric flow water, containing sand, fracturing fluids and debris from the formation with very little gas being brought to the surface, usually in multiphase slug flow. Due to the high volume of the flowback and the small amounts of gas in the initial flowback, operation of a separator may be initially technically infeasible, and there may not be sufficient gas for combustion. During these conditions, the emissions cannot be controlled from the flowback. During this stage, liquids are collected and routed to completion vessels.

For the reasons explained above, during the initial flowback stage, we propose that the flowback be routed to a storage vessel or to a well completion vessel that can be a frac tank, a lined pit or any other vessel. The purpose of this requirement is to avoid having operators route the flowback to an unlined pit or onto the ground. During the initial flowback stage, there is no requirement for controlling emissions from the vessel, and any gas in the flowback during this stage may be vented. However, the operator must route the flowback to a separator unless it is technically infeasible for a separator to function. Conditions that could prevent proper operation of the separator include insufficient gas concentration, low pressure gas, and multiphase slug flow containing solids that could clog the separator. We stress that operators have the responsibility to direct the flowback to a separator as soon as conditions allow a separator to function and in accordance with the General Provision requirements to operate the affected facility in a manner consistent with good air pollution control practices for minimizing emissions.

The second stage is defined as the ''separation flowback stage.'' The point at which the separator can function

[82] Because the current NSPS requires control of gas well completions using this option, we do not include the secondary emissions for control of methane from gas well completions.

marks the beginning of the separation flowback stage. This stage is characterized by the separator operating with a gaseous phase and one or more liquid phases in the separator. The end of the separation flowback stage marks the end of the flowback period and is defined as the point at which the well is shut in and the flowback equipment is permanently disconnected from the well, or the startup of production. The end of the separation flowback stage (i.e., the end of flowback) is characterized by certain indicators. Permanent disconnection of the temporary equipment used during flowback can be an indicator of flowback having ended. For example, during flowback, skid-mounted choke manifolds are used to limit flowback and assist in directing the flow. Temporary lines laid on the ground from the wellhead to the choke manifold and to the flowback separators and frac tanks are connected with ''hammer unions'' which are pipe unions that are designed for ease of making temporary connections and are characterized by ''ears'' that allow the joint to be made up quickly by striking with a hammer. After flowback has subsided and the well has cleaned up sufficiently, the well is temporarily shut in to disconnect the temporary flowback equipment. We believe that when the operator permanently disconnects choke manifolds, temporary separators, sand traps and other equipment connected with temporary lines and hammer unions, it is a reliable indicator that flowback has ended and the well is ready for production. At that point, we believe that operators will remove these temporary equipment used during flowback to avoid incurring unnecessary charges for additional days the equipment remains onsite. The well could start production immediately or it could remain shut in until permanent equipment is installed.

During the separation flowback stage, the operator must route all salable quality natural gas from the separator to a gas flow line or collection system, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose that a purchased fuel or raw material would serve. If, during the separation flowback stage, it is technically infeasible to route the recovered gas to a flow line or collection system, re-inject the gas or use the gas as fuel or for other useful purpose, the recovered gas must be combusted. No direct venting of recovered gas is allowed during the separation flowback stage except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. With regard to infeasibility of collecting the salable quality gas, we believe that owners and operators plan their operations to extract a target product and evaluate whether the appropriate infrastructure access is available to ensure their product has a viable path to market before completing a well. However, there may be cases in which, for reason(s) not within an operator's control, the well is completed and flowback occurs without a suitable flow line available. We are aware that this situation may be more common for wells that are primarily drilled to produce oil. In those instances, § 60.5375(a)(3) requires the combustion of the gas unless combustion poses an unsafe condition as described above. During the separation flowback stage, all liquids from the separator must be directed to a storage vessel or to a well completion vessel, routed to a collection system or be re-injected into the well or another well.

The proposed operational standard would be accompanied by requirements for documentation of the overall duration of the completion event, duration of recovery using REC, duration of combustion, duration of venting, and specific reasons for venting in lieu of combustion.

2. Proposed Standards for Hydraulically Fractured Exploratory and Delineation Wells (Subcategory 2 Wells)

In the 2012 NSPS, we established VOC standards for subcategory 2 hydraulically fractured exploratory and delineation gas well completions. In this action, we are proposing VOC standards for the hydraulically fractured exploratory and delineation oil well completions and we are also proposing methane standards for all hydraulically fractured exploratory and delineation well completions in the oil and natural gas source category. Based on the analysis below, the proposed VOC and methane standards described above are the same as the current standards for hydraulically fractured exploratory and delineation gas well completion standards currently in the NSPS.

As noted above, for the 2012 NSPS analysis, we determined that the emissions profile for subcategory 2 wells is the same as subcategory 1 wells as described above. In our review of white paper comment and other information for this action, we found no information that would indicated this conclusion is not still valid. Specifically, we determined the emissions from a hydraulically fractured oil well were 9.72 tons of methane and 8.14 tons of VOC per 3-day completion event.[83]

In our analysis for the 2012 NSPS, we determined that a REC is not an option for subcategory 2 wells because there is no infrastructure in place to get the recovered gas to market or further processing. Typically, these types of wells generally are not in proximity to existing gathering lines at the time the well is completed. Therefore, for these wells, the only potential control option identified (both under the 2012 NSPS and under this action) is combustion of gases using a completion combustion device, as described above. Also as explained above, because of the high-volume, multiphase slug flow nature of the flowback gas, water and sand, control by a traditional flare or other control devices, such as vapor recovery units, is infeasible, since these devices would be overcome by the erratic high-volume flow of liquids, which leaves combustion as the only available control system for subcategory 2 wells. As also discussed above, combustion can present a fire hazard or other undesirable impacts in some situations. In our review of white paper comment and other information for this action, we found no information that would indicate this conclusion is not still valid.

Based on the 95 percent emission reduction of a completion combustion device, the emission reductions for a subcategory 2 hydraulically fractured gas well completion or recompletion are estimated to be 147.4 tons of methane per completion event.[84] The emission reductions for a subcategory 2 hydraulically fractured oil well completion or recompletion event are estimated to be around 9.23 tons of methane and 7.73 tons of VOC per 3-day completion.

As noted above, for purposes of this action, we have identified in section VIII.A two approaches (single pollutant and multipollutant approaches) for evaluating whether the cost of a multipollutant control is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the single pollutant approach, we assign all costs to the reduction of

[83] Emissions of VOC from hydraulically fractured subcategory 2 gas wells are subject to the current NSPS and are not included in this action.

[84] Emissions of VOC from hydraulically fractured subcategory 2 gas wells are subject to the current NSPS and are not included in this action.

one pollutant and zero to all other pollutants simultaneously reduced. For this approach, we would find the cost of control reasonable if it is reasonable for reducing one pollutant alone. As shown in the evaluation below, which assigns all the costs to methane reduction alone, based on an average annual cost of $3,723 per completion, the cost of control for a completion combustion device is estimated to be $24 per ton of methane for subcategory 2 gas well completion event. We find these costs to be reasonable for the amount of methane reduction it can achieve. Also, because all the costs have been attributed to methane reduction, the cost of the simultaneous VOC reduction is zero and therefore reasonable.[85] We estimate the cost of control for subcategory 2 oil wells to be $403 per ton of methane and $481 per ton of VOC per oil well completion. We consider these costs to be reasonable considering the level of emissions reductions.

We also evaluated the cost of this control under the multipollutant approach. Under this approach, the costs would be allocated based on the estimated percentage reduction expected for each pollutant. Because completion combustion devices reduces both methane and VOC by 95 percent, we attributed 50 percent of the costs to methane reduction and 50 percent of the cost to VOC reduction. The costs for methane reduction would be half of the estimated costs under the first approach above, for both gas and oil wells, which we have found to be reasonable. See the TSD, available in the docket for this action, for a detailed description of the cost of control analysis.

Aside from the potential hazards associated with use of a completion combustion device in some cases, we did not identify any nonair environmental impacts, health or energy impacts associated with completion combustion devices, therefore no analysis was completed. However, completion combustion devices would produce combustion-related air pollutants. For 870 subcategory 2 oil well completion[86] for the projected year 2020, we estimated that 66 tons of total hydrocarbons, 175 tons of carbon monoxide, 62,628 tons of carbon dioxide, 32 tons of nitrogen oxides and 1 ton of particulate matter would be produced as secondary emissions. This is based on the assumption that 95 percent of flowback gas is combusted by the combustion device. This control option is estimated to reduce emissions for the projected year 2020 by 135,516 tons of methane and 113,481 tons of VOC. Thus, we believe that the benefit of the methane and VOC reduction far outweighs the secondary impact of combustion-related pollutants as a result of completion combustion control.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For the capital expenditure analysis, we used the capital expenditures for 2012 for NAICS 2111, 213111 and 213112 as reported in the U.S. Census data, which we believe are representative of the production segment. The total capital cost for complying with the proposed standards for subcategory 2 wells is 0.002 percent of the capital expenditures, which is well below the percentage capital increase that courts have previously upheld as reasonable as discussed in Section VIII.A.. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized cost for complying with the proposed standards is 0.001 percent of the total revenues, which is also very low.

For all types of affected facilities in the production segment, the total capital costs for complying with the proposed standards is 0.16 percent of the total capital expenditures, and the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

In light of the above, we propose to determine that the BSER for subcategory 2 wells would be use of a completion combustion device. As we explained above, the gas is discharged at multiple locations during flowback and is mixed with water and sand in multiphase slug flow and therefore we determined that it is not feasible to set a numerical performance standard.

Pursuant to CAA section 111(h)(2), we are proposing an operational standard for subcategory 2 well completions that would require minimization of venting of gas and hydrocarbon vapors during the completion operation through the use of a completion combustion device, with provisions for venting in lieu of combustion for situations in which combustion would present safety hazards or for periods when the flowback gas is noncombustible. The owners and operators of these wells also have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

As with subcategory 1 wells, for the purposes of these standards we have separated the flowback period into two stages, the ''initial flowback stage'' and the ''separation flowback stage.'' During the initial flowback stage, the requirements for the subcategory 2 wells would be the same as the subcategory 1 wells. The flowback must be routed to a storage vessel or to a well completion vessel that can be a frac tank, a lined pit or any other vessel. During the initial flowback stage, there is no requirement for controlling emissions from the vessel, and any gas in the flowback during this stage may be vented.

During the separation flowback stage, the operator must route all salable quality gas from the separator to a gas flow line or collection system, combust the gas, re-inject the gas into the well or another well, use the gas as an on-site fuel source or use the gas for another useful purpose that a purchased fuel or raw material would serve. No direct venting of recovered gas is allowed during the separation flowback stage except when combustion creates a fire or safety hazard or can damage tundra, permafrost or waterways. During the separation flowback stage, all liquids from the separator must be directed to a storage vessel or to a well completion vessel, routed to a collection system or re-injected into the well or another well.

Consistent with requirements for subcategory 1 wells, owners or operators of subcategory 2 wells would be required to document completions and provide justification for periods when gas was vented in lieu of combustion.

We estimate that these control options for these sources would reduce the total emissions from all hydraulically fractured and refractured oil well completions for the projected year 2020 by 135,516 tons of methane and 113,481 tons of VOC. Thus, we believe that the benefit of the methane and VOC reductions far outweigh the secondary impact of combustion emissions formation during use of the completion combustion operation.

Several public and peer reviewer comments on the white paper noted that these technologies are currently in regular use by industry to control oil well completion and recompletion

[85] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from hydraulically fractured subcategory 2 gas well completions. We are not reopening that decision in this action. Therefore, this cost finding is relevant only to methane from hydraulically fractured subcategory 2 gas well completions.

[86] Because subcategory 2 hydraulically fractured gas well completions are subject to the current NSPS, we do not consider secondary impacts for the destruction of methane under this action.

emissions.[87] In addition, these control technologies are the same as those required in the 2012 NSPS to control completion emissions from hydraulically fractured gas well completions.

The EPA is aware that oil wells cannot perform a REC if there is not sufficient well pressure or gas content during the well completion to operate the surface equipment required for a REC. In the 2012 NSPS the EPA did not require low pressure gas wells to perform REC, but operators were required to control those well completions using combustion.[88] We solicit comment on the types of oil wells that will not be capable of performing a REC or combusting completion emissions due to technical considerations such as low pressure or low gas content, or other physical characteristics such as location, well depth, length of hydraulic fracturing, or drilling direction (e.g., horizontal, vertical, directional).[89] Additionally, we solicit comment on all aspects of our proposal to regulate methane and VOC emissions from hydraulically fractured oil well completions.

As shown in the analyses presented above, the BSER for hydraulically fractured oil wells is the same as that for gas wells. Accordingly, we are proposing to apply the current requirements for hydraulically fractured gas well completions to hydraulically fractured oil well completions. It is logical that the BSER analyses would result in the same BSER determinations for hydraulically fractured gas and oil wells, because the available options for controlling emissions and their current use in the field are the same. Several public and peer reviewer comments on the white paper noted that the control technologies used for controlling emissions from hydraulically fractured oil well completions are the same as those used for completions of hydraulically fractured gas wells. The commenters further noted that in many cases it is difficult to distinguish gas wells from oil wells, because many wells produce both gas and oil. Consistent standards for completions of hydraulically fractured gas wells and completions of hydraulically fractured oil wells will remove the need for operators to distinguish a gas well completion from an oil well completion for the purposes of complying with subpart OOOO. This change will improve the implementation of the standards by providing greater certainty as to which well completions must comply with the standards.

We are requesting comment on excluding low production wells (i.e., those with an average daily production of 15 barrel equivalents or less)[90] from the standards for well completions. It is our understanding that low production wells have inherently low emissions from well completions and many are owned and operated by small businesses. We are concerned about the burden of the well completion requirement on small businesses, in particular where there is little emission reduction to be achieved. We recognize that identification of these wells prior to completion events is difficult. We believe that drilling of a low production well may be unintentional and may be infrequent, but production may nevertheless proceed due to economic reasons. We solicit comment and information on emissions associated with low production wells, characteristics of these wells and supporting information that would help owners/operators and enforcement personnel identify these wells prior to completion. In addition, we understand that a daily average of 15 barrel equivalents is representative of low production wells for some purposes, we solicit comment on the appropriateness of this threshold for applying the standards for well completions.

Further, we are proposing that wells with a gas-to-oil ratio (GOR) of less than 300 scf of gas per barrel of oil produced would not be affected facilities subject to the well completion provisions of the NSPS.[91] We solicit comment on whether a GOR of 300 is the appropriate applicability threshold, and if the GOR of nearby wells would be a reliable indicator in determining the GOR of a new or modified well. The reason for the proposed threshold GOR of 300 is that separators typically do not operate at a GOR less than 300, which is based on industry experience rather than a vetted technical specification for separator performance. Though, in theory, any amount of free gas could be separated from the liquid, the reality is that this is not practical given the design and operating parameters of separation units operating in the field.

We believe that having no threshold may create a significant burden for operators to control emissions for these wells with just a trace of gas. EIA data show that the number of ''oil only'' wells drilled from 2007–2012 was less than 20 percent.[92] The potential emission characteristic of oils with a GOR of 300 is relevant when deciding whether this is a reasonable threshold. Primarily, the concern is volatility. The threshold must be low enough that the oil produced is considered non-volatile. Non-volatile ''black oils'' (oil likely to not have gases or light hydrocarbons associated with it) are generally defined as having GOR values in the range of 200 to 900.[93] Therefore, oil wells with GORs less than 300 are at the lower end of this range, and will not likely have enough gas associated that it can be separated. Therefore, the EPA is proposing that the NSPS requirements for well completions do not apply to completions wells with hydraulic fracturing that have a GOR of less than 300 scf/barrel.

We are soliciting comment on whether the well completion provisions of the proposed rule can be implemented on the effective date of the rule in the event of potential shortage of REC equipment and, if not, how a phase in could be structured. We believe that there will be a sufficient supply of REC equipment available by the time the NSPS becomes effective. However, we request comment on whether sufficient supply of this equipment and personnel to operate it will be available to accommodate the increased number of RECs by the effective date of the NSPS. We also request specific estimates of how much time would be required to get enough equipment in operation to accommodate the full number of RECs performed annually. In the event that public comments indicate that available equipment would likely be insufficient to accommodate the increase in number of REC performed, we are considering phasing in requirements for well completions in the final rule. Such a phased in approach could be structured

[87] The EPA received six peer review comments and several submissions of technical information and data on this paper, available for review at *http://www.epa.gov/airquality/oilandgas/whitepapers.html*.

[88] Following publication of the 2012 NSPS, EPA received a joint petition for administrative reconsideration of the rule. The petitioners questioned the technical merits of the low pressure well definition and asserted that the public had not had an opportunity to comment on the definition. EPA re-proposed the definition of ''low pressure gas well,'' on March 23, 2015 (80 FR 15180), and took comment on IPAA's alternative definition. EPA has finalized this definition in a separate action.

[89] Many of these data are available in the DrillingInfo database. More information is available at: *http://info.drillinginfo.com*.

[90] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[91] On February 24, 2015, API submitted a comment to EPA stating that oil wells with GOR values less than 300 do not have sufficient gas to operate a separator. *http://www.regulations.gov/#!documentDetail;D=EPA-HQ-OAR-2014-0831-0137*.

[92] *http://www.eia.gov/todayinenergy/detail.cfm?id=13571#*.

[93] *http://petrowiki.org/Oil_fluid_characteristics*.

to provide for control of the highest emitting wells first, with other wells being included at a later date. We solicit comment on whether GOR of the well and production level of the well should be bases for the phasing of requirements for RECs. We also solicit suggestions for other ways to address a potential short-term REC equipment shortage that may hinder operators' compliance with the proposed NSPS. Additionally, we solicit comment on what an appropriate threshold should be for low production wells.

Finally, we solicit comment on criteria that could help clarify availability of gathering lines. Availability of a gathering line is one consideration affecting feasibility of recovery of natural gas during completion of hydraulically fractured wells. There are several factors that can affect availability of a gathering line including, but not limited to, the capacity of an existing gathering line to accept additional throughput, the ability of owners and operators to obtain rights of way to cross properties, and the distance from the well to an existing gathering line. We are aware that some states require collection of gas if a gathering line is present within a specific distance from the well. For example, Montana allows gas from wells to be flared only in cases where the well is farther than one-half mile from a gas pipeline.[94] We solicit comment on whether distance from a gathering line is a valid criterion on which to base requirements for gas recovery and, if so, what would an appropriate distance for such a threshold. In addition, we solicit comment on any other factors that could be specified in the NSPS for requiring recovery of gas from well completions.

3. Use of a Separator During Flowback

For subcategory 1, subcategory 2 and low pressure gas wells, the current NSPS at § 60.5375(a) and (f) requires routing of flowback to a separator unless it is technically infeasible for a separator to function. The NSPS also provides in § 60.5375(f) that subcategory 2 and low pressure wells are required to control emissions through combustion using a completion combustion device (which can include a pit flare) rather than being required to perform a REC. It was our understanding that a separator could be used at some point during the flowback period of every well completion. Recent information indicates that some wells, because of certain characteristics of the reservoir, do not need to employ a separator. In those cases, we understand that operators direct the flowback to a pit and can combust gas contained in the flowback as it emerges from the pipe. At some point, after the well has flowed sufficiently to clean up the wellbore and the gas is of salable quality, production begins or the well is temporarily shut in. As a result of this new information, our initial understanding may not apply.

We solicit comment on (1) the role of the separator in well completions and whether a separator can be employed for every well completion; and (2) the appropriate relationship of the separator in the context of our requirements that cover a very broad spectrum of wells. We solicit further information that would help inform our consideration of this issue as we seek to ensure we have adequately established appropriate requirements for all well completions subject to the NSPS.

G. Proposed Standards for Fugitive Emissions From Well Sites and Compressor Stations

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks'' [95] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the mitigation techniques (practices and technology) available to reduce these emissions along with the cost and effectiveness of these practices and technologies.

The detection of fugitive emissions from oil and natural gas well sites and compressor stations, which are comprised of compressors at natural gas transmission, storage, gathering and boosting stations, can be determined using several technologies. Historically, fugitive emissions were detected using sensory monitoring (*e.g.,* visual, olfactory or sound) or EPA Method 21 to determine if a leak exceeded a set threshold (*e.g.,* the leak concentration was greater than the leak definition for the component). As described in the white paper, we found that many fugitive emission surveys are now conducted using OGI in the oil and natural gas source category, a technology that provides a visible image of gas emissions or leaks to the atmosphere. The OGI instrument works by using spectral wavelength filtering and an array of infrared detectors to visualize the infrared absorption of hydrocarbons and other gaseous compounds. As the gas absorbs radiant energy at the same waveband that the filter transmits to the detector, the gas and motion of the gas is imaged. The OGI instrument can be used for monitoring a large array of components at a facility and is an effective means of detecting fugitive emissions when the technology is used appropriately.

Several studies in the white paper estimated that OGI can monitor 1,875–2,100 components per hour. In comparison, the average screening rate using a Method 21 instrument (*e.g.,* organic vapor analyzer, flame ionization detector, flow measurement devices) is roughly 700 components per day. However, the EPA's recent work with OGI instruments suggests these studies underestimate the amount of time necessary to thoroughly monitor components for fugitive emissions using OGI instruments. Even though the amount of time may be underestimated, we believe the use of OGI can reduce the amount of time necessary to conduct fugitive emissions monitoring since multiple fugitive emissions components can be surveyed simultaneously, thus reducing the cost of identifying fugitive emissions in upstream oil and natural gas facilities when compared to using a handheld TVA or OVA, which requires a manual screening of each fugitive emissions component.

1. Fugitive Emissions From Well Sites

Fugitive emissions may occur for many reasons at well sites such as when connection points are not fitted properly, thief hatches are not properly weighted or sealed or when seals and gaskets start to deteriorate. Changes in pressure or mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions, fugitive emissions components, include agitator seals, connectors, pump diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, pump seals, valves or open thief hatches or holes in storage vessels, pressure vessels, separators, heaters and meters. For purposes of this proposed rule, fugitive emissions do not include venting emissions from devices that vent as part of normal operations, such as gas-driven pneumatic controllers or gas-driven pneumatic pumps.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at well sites: (1) A

[94] Administrative Rules of Montana (ARM) Title 17 Chapter 8 Air Quality Subchapter 16—Emission Control Requirements for Oil and Gas Well Facilities Operating Prior to Issuance of a Montana Air Quality Permit. Emission Control Requirements, 17.8.1603 Available at: *http://www.deq.mt.gov/dir/legal/Chapters/Ch08-toc.mcpx.*

[95] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual survey frequency. For Method 21 monitoring and repair, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definition concentrations for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI instrumentation). EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[96]

In order to estimate fugitive methane and VOC emissions from well sites, we used fugitive emissions component counts from the GRI/EPA report[97] for natural gas production well sites, and fugitive emissions component counts from the GHG inventory and API for oil production well sites. The types of production equipment located at natural gas production well pads include: Gas wellheads, separators, meters/piping, heaters, and dehydrators. The types of oil well production equipment include: Oil well heads, separators, headers and heater/treaters. The types of fugitive emissions components that are associated with both oil and natural gas wells include but are not limited to: Valves, connectors, open-ended lines and valves (OEL), and pressure relief device (PRD). Fugitive emissions component counts for each piece of equipment in the gas production segment were calculated using the average fugitive emissions component counts in the Eastern U.S. and the Western U.S. from the EPA/GRI report. These data were used to develop a natural gas well site model plant. Fugitive emissions components counts for these equipment types in the oil production segment were obtained from an American Petroleum Institute (API) workbook.[98] These data were used to develop an oil production well site model plant.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of fugitive emissions components that would typically be found at a well site.

The fugitive emission factors from AP–42,[99] which provided a single source of total organic compounds (TOC) emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for oil and natural gas production well sites. Using the AP–42 factors, the methane and VOC fugitive emissions from a natural gas well site are estimated to be 4.5 tpy and 1.3 tpy, respectively. For an oil production well site, the estimated fugitive methane and VOC emissions are 1.1 tpy and 0.3 tpy, respectively. The calculation of these emission estimates are explained in detail in the background TSD for this proposal available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9)* and the *FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[100] We used these data along with the monitoring frequency (*e.g.,* annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected

[96] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[97] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[98] API Workbook 4638, 1996.

[99] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

[100] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180.

emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[101] For purposes of this action, we have identified in section VIII.A two approaches (single and multipollutant approaches) for evaluating the cost-effectiveness of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above for reducing both methane and VOC emissions. As explained in that section, we believe that both the single and multipollutant approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be warranted as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we allocate the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC emissions are controlled proportionally equal, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (i.e., quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (i.e., 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies for a model well site are estimated to be more cost-effective than Method 21 for those same monitoring frequencies.[102] We therefore focus our BSER analysis based on the use of OGI.

For the reasons stated below, we find that the control cost based on quarterly monitoring using OGI may not be cost-effective based on the information available. As shown in the TSD, under the single pollutant approach, if all costs are assigned to methane and zero to VOC reduction, the cost is $3,753 per ton of methane reduced, and $3,521 per ton if savings of the natural gas recovered is taken into account. If all costs are assigned to VOC and zero to methane reduction, the cost is $13,502 per ton of VOC reduced, and $12,668 per ton if savings of the natural gas recovered is taken into account. Under the multipollutant approach, the cost of control for VOC based on quarterly monitoring is $6,751 per ton, and $6,334 per ton of VOC reduced if savings are considered. In a previous NSPS rulemaking [72 FR 64864 (November 16, 2007)], we had concluded that a VOC control option was not cost-effective at a cost of $5,700 per ton. In light of the above, we find that the cost of monitoring/repair based on quarterly monitoring at well sites using OGI is not cost-effective for reducing VOC and methane emissions under either approach. Having found the control cost using OGI based on quarterly monitoring not to be cost-effective, we now evaluate the control cost based on annual and semi-annual monitoring using OGI. As shown in the TSD, the costs between annual and semi-annual monitoring are comparable. Because semi-annual monitoring achieves greater emissions reduction, we focus our analysis on the cost based on semi-annual monitoring.

While the cost appears high under the single pollutant approach, we find the costs to be reasonable under the multipollutant approach for the following reasons. As shown in the TSD, for VOC reduction, the cost is $4,979 per ton; when savings of the natural gas recovered are taken into account, the cost is reduced to $4,562 per ton. For methane reduction, the control cost is $1,384 per ton; when cost savings of the natural gas recovered is taken into account, the cost is reduced to $1,268 per ton. As explained above, we believe that we have underestimated the emissions from these well sites; therefore, we believe the use of OGI is more cost-effective than the amount presented here. Furthermore, while being used to survey fugitive components at a well site, the OGI may potentially help an owner and operator detect and repair other sources of visible emissions not covered by the NSPS. One example would be an intermittently acting pneumatic controller that is stuck open. The OGI could help the owner and operator detect and address and reduce such inadvertent emissions, resulting in more cost saving from more natural gas recovered.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at well sites, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 211111, 211112 and 213112, which we believe are representative of the production segment. The total annualized costs for complying with the proposed standards is 0.085 percent of the total revenues, which is very low.

For all types of affected facilities in the production, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at well sites based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot not be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in TSD, the cost of conducting resurvey using Method 21 is $2 per component, which is reasonable.

[101] See pages 68–69 of the TSD.

[102] See the 2015 TSD for full comparison.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurvey fugitive components at well sites. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at well sites is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

As mentioned above, OGI monitoring requires trained OGI personnel and OGI instruments. Many owners and operators, in particular small businesses, may not own OGI instruments or have staff who are trained and qualified to use such instruments; some may not have the capital to acquire the OGI instrument or provide training to their staff. While our cost analysis takes into account that owners and operators may need to hire contractors to perform the monitoring survey using OGI, we do not have information on the number of available contractors and OGI instruments. In light of our estimated 20,000 active wells in 2012 and that the number will increase annually, we are concerned that some owners and operators, in particular small businesses, may have difficulty securing the requisite OGI contractors and/or OGI instrumentation to perform monitoring surveys on a semi-annual basis. Larger companies, due to the economic clout they have by offering the contractors more work due to the higher number of wells they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services. In light of the potential concern above, we are co-proposing monitoring survey on an annual basis at the same time soliciting comment and supporting information on the availability of trained OGI contractors and OGI instrumentation to help us evaluate whether owners and operators would have difficulty acquiring the necessary equipment and personnel to perform a semi-annual monitoring and, if so, whether annual monitoring would alleviate such problems.

Recognizing that additional data may be available, such as emissions from super emitters that may have higher emission factors than those considered in this analysis, we are also taking comment on requiring monitoring survey on a quarterly basis.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

[A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from well sites are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components at a well site. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from the collection of fugitive emission components at well sites.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a well site and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards.[103] That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at well sites.[104]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[105] Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of fugitive methane and VOC emissions come from a minority of components (e.g., gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. As shown in our TSD, we estimate the number of fugitive emission components at a well site to be around 700. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the well site has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the well site has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions. Under the proposed standards, the affected facility would be

[103] In our TSD we estimate the number of fugitive emissions components to be around 700 and of those components we estimate that about 1 percent would need to be repaired.

[104] This timelines is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[105]

defined as the collection of fugitive emissions components at a well site. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump would be considered fugitive emissions.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.1, for purposes of the proposed standards for fugitive emissions at well sites, modification of a well site is defined as when a new well is drilled or a well at the well site (where collection of fugitive emissions components are located) is hydraulically fractured or refractured. As explained in that section, other than these events, we are not aware of any other physical change to a well site that would result in an increase in emissions from the collection of fugitive components at such well site. To clarify and ease implementation, we propose to define ''modification'' to include only these two events for purposes of the fugitive emissions provisions at well sites.

In the 2012 NSPS, we provided that completion requirements do not apply to refracturing of an existing well that is completed responsibly (i.e. green completions). Building on the 2012 NSPS, the EPA intends to continue to encourage corporate-wide voluntary efforts to achieve emission reductions through responsible, transparent and verifiable actions that would obviate the need to meet obligations associated with NSPS applicability, as well as avoid creating disruption for operators following advanced responsible corporate practices. It has come to our attention that some owners and operators may already have in place, and are implementing, corporate-wide fugitive emissions monitoring and repair programs at their well sites that are equivalent to, or more stringent than our proposed standards. Such corporate efforts present the potential to further the development of LDAR technologies. To encourage companies to continue such good corporate policies and encourage advancement in the technology and practices, we solicit comment on criteria we can use to determine whether and under what conditions well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well site fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards). We recognize that meeting an NSPS performance level should not, standing alone, be a basis for a source not becoming an affected facility.

For the reasons stated above, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified well sites operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for well sites fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (i.e., how to assure that these well sites are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all fugitive emissions components at modified well sites or just to those components that are connected to the fractured, refractured or added well. For some modified well sites, the fractured or refractured or added well may only be connected to a subset of the fugitive emissions components on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a well site since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (e.g., wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 monitoring surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at a well site within 30 days of the initial startup of the first well completion for a new well or within 30 days of well site modification. We are proposing a 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI technicians and operators to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI technicians and operators to perform surveys and repairs.

We are proposing to exclude low production well sites (i.e., a low production site is defined by the average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production) [106] from the standards for fugitives emissions from well sites. We believe the lower production associated with these wells would generally result in lower fugitive emissions. It is our understanding that fugitive emissions at low production well sites are inherently low and that such well sites are mostly owned and operated by small businesses. We are concerned about the burden of the fugitive emission requirement on small businesses, in particular where there is little emission reduction to be achieved. To more fully evaluate the exclusion, we solicit comment on the air emissions associated with low production wells, and the relationship between production and fugitive emissions. Specifically, we solicit comment on the relationship between production and fugitive emissions over time. While we have learned that a daily average of 15 barrel per day is representative of low production wells, we solicit comment on the appropriateness of this threshold for applying the standards for fugitive emission at well sites. Further, we solicit comment on whether EPA should include low production well sites for fugitive emissions and if these types of well sites are not excluded, should they have a less frequent monitoring requirement.

We are also requesting comment on whether there are well sites that have inherently low fugitive emissions, even when a new well is drilled or a well site is fractured or refractured and, if so, descriptions of such type(s) of well sites. The proposed standards are not intended to cover well sites with no fugitive emissions of methane or VOC. We are aware that some sites may have inherently low fugitive emissions due to the characteristics of the site, such as the gas to oil ratio of the wells or the specific types of equipment located on the well site. We solicit comment on these characteristics and data that would demonstrate that these sites have low methane and VOC fugitive emissions.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring surveys should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

2. Fugitive Emissions From Compressor Stations

Fugitive emissions at compressor stations in the oil and natural gas source category may occur for many reasons (*e.g.,* when connection points are not fitted properly, or when seals and gaskets start to deteriorate). Changes in pressure and mechanical stresses can also cause fugitive emissions. Potential sources of fugitive emissions include agitator seals, distance pieces, crank case vents, blowdown vents, connectors, pump seals or diaphragms, flanges, instruments, meters, open-ended lines, pressure relief devices, valves, open thief hatches or holes in storage vessels, and similar items on glycol dehydrators (*e.g.,* pumps, valves, and pressure relief devices). Equipment that vents as part of normal operations, such as gas driven pneumatic controllers, gas driven pneumatic pumps or the normal operation of blowdown vents are not considered to be sources of fugitive emissions.

Based on our review of the public and peer review comments on the white paper and the Colorado and Wyoming state rules, we believe that there are two options for reducing methane and VOC fugitive emissions at compressor stations: (1) A fugitive emissions monitoring program based on individual component monitoring using EPA Method 21 for detection combined with repairs, or (2) a fugitive emissions monitoring program based on the use of OGI detection combined with repairs. Several public and peer reviewer comments on the white paper noted that these technologies are currently used by industry to reduce fugitive emissions from the production segment in the oil and natural gas industry.

Each of these control options are evaluated below based on varying the frequency of conducting the monitoring survey and fugitive emissions repair threshold (*e.g.,* the specified concentration when using Method 21 or visible identification of methane or VOC when an OGI instrument is used). For our analysis, we considered quarterly, semiannual and annual monitoring frequencies. For Method 21, we considered 10,000 ppm, 2,500 ppm and 500 ppm fugitive repair thresholds. The leak definitions for other NSPS referencing Method 21 range from 500–10,000 ppm. Therefore, we selected 500 ppm, 2,500 ppm and 10,000 ppm. For OGI, we considered visible emissions as the fugitive repair threshold (*i.e.,* emissions that can be seen using OGI). EPA's recent work with OGI indicate that fugitive emissions at a concentration of 10,000 ppm are generally detectable using OGI instrumentation, provided that the right operating conditions (*e.g.,* wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI.[107]

In order to estimate fugitive emissions from compressor stations, we used component counts from the GRI/EPA report [108] for each of the compressor station segments. Fugitive emission factors from AP–42 [109] were used to estimate emissions from gathering and boosting stations in the production

[106] For the purposes of this discussion, we define 'low production well' as a well with an average daily production of 15 barrel equivalents or less. This reflects the definition of a stripper well property in IRC 613A(c)(6)(E).

[107] Draft Technical Support Document Appendices, Optical Gas Imaging Protocol (40 CFR part 60, Appendix K), August 11, 2015.

[108] Gas Research Institute/U.S. Environmental Protection Agency, Research and Development, Methane Emission Factors from the Natural Gas Industry, Volume 8, Equipment Leaks, June 1996 (EPA–600/R–96–080h).

[109] Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

segment and emission factors from the GRI/EPA report were used to estimate fugitive emission from transmission and storage compressor stations and evaluate the cost of control for these segments.

Since we have emission factors for only a subset of the components which are possible sources for fugitive emissions, our emission estimates are believed to be lower than the emissions profile for the entire set of components that would typically be found at a compressor station.

The fugitive emission factors from AP–42,[110] which provided a single source of TOC emission factors that include non-VOCs, such as methane and ethane, were used to estimate emissions and evaluate the cost of control of a fugitive emissions program for compressor stations. Using the GRI/EPA and AP–42 data, fugitive emissions from gathering and boosting stations were estimated to be 35.1 tpy of methane and 9.8 tpy of VOC. Fugitive emissions from natural gas transmission stations were estimated to be 62.4 tpy of methane and 1.7 tpy of VOC. Fugitive emissions from natural gas storage facilities were estimated to be 164.4 tpy of methane and 4.6 tpy of VOC. The calculation of these emission estimates are explained in detail in the TSD available in the docket.

Information in the white paper related to the potential emission reductions from the implementation of an OGI monitoring program varied from 40 to 99 percent. The causes for this range in reduction efficiency were the frequency of monitoring surveys performed and different assumptions made by the study authors. According to the calculations, which are based on uncontrolled emission factors for well pads contained within the EPA Oil and Natural Gas Sector Technical Support Document (2011), the Colorado Air Quality Control Commission, *Initial Economic Impact Analysis for Proposed Revisions to Regulation Number 7 (5 CCR 1001–9) and the FINAL ECONOMIC IMPACT ANALYSIS For Industry's Proposed Revisions to Colorado Air Quality Control Commission Regulation Number 3, 6, and 7 (5 CCR 1001–9)* (January 30, 2014), a -quarterly monitoring program in combination with a repair program can reasonably be expected to reduce fugitive methane and VOC emissions at well sites by 80 percent. Although information in the white paper indicated emission reductions as high as 99 percent may be achievable with OGI, we do not believe such levels can be consistently achieved for all of types of components that may be subject to a fugitive emissions monitoring program. Therefore, using engineering judgement and experience obtained through our existing programs for finding and repairing leaking components, we selected 80 percent as an emission reduction level that can reasonably be expected to be achieved with a quarterly monitoring program. Due to the increased amount of time between each monitoring survey and subsequent repair, we believe that the level of emissions reduction achieved by less frequent monitoring surveys will be reduced from this level. Therefore, we assigned an emission reduction of 60 percent to semiannual monitoring survey and repair frequency and 40 percent to annual frequency, consistent with the reduction levels used by the Colorado Air Quality Control Commission in their initial and final economic impacts analyses. We solicit comment on the appropriateness of the percentage of emission reduction level that can be reasonably expected to be achieved with quarterly, semiannual, and annual monitoring program frequencies.

For Method 21, we estimated emissions reductions using The EPA Equipment Leaks Protocol document, which provides emissions factor data based on leak definition and monitoring frequencies primarily for the Synthetic Organic Chemical Manufacturing Industry (SOCMI) and Petroleum Refining Industry along with the emissions rates contained within the Technology Review for Equipment Leaks document.[111] We used these data along with the monitoring frequency (*e.g.*, annual, semiannual, and quarterly) at fugitive repair thresholds at 500, 2,500 and 10,000 ppm to determine uncontrolled emissions. Using this information we calculated an expected emissions reduction percentage for each of the combinations of monitoring frequency and repair threshold which range from.

We also looked at the costs of a monitoring and repair program under various monitoring frequencies and repair thresholds (for Method 21), including the cost of OGI monitoring survey, repair, monitoring plan development, and the cost-effectiveness of the various options.[112] For purposes of this action, we have identified in section VIII.A two approaches (single pollutant and multipollutant approaches) for evaluating whether the cost of a multipollutant control, such as the fugitive emissions monitoring and repair programs identified above, is reasonable. As explained in that section, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), we assign all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced. Under the second approach (multipollutant approach), we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In the multipollutant approach, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. In this evaluation, we evaluated both approaches across the range of identified monitoring survey options: OGI monitoring and repair performed quarterly, semiannually and annually; and Method 21 monitoring performed quarterly, semiannually and annually, with a fugitive emissions repair threshold of 500, 2,500 and 10,000 ppm at each frequency. The calculation of the costs, emission reductions, and cost of control for each option are explained in detail in the TSD. As shown in the TSD, while the costs for repairing components that are found to have fugitive emissions during a fugitive monitoring survey remain the same, the annual repair costs will differ based on monitoring frequency.

As shown in our TSD, both OGI and Method 21 monitoring survey methodologies costs generally increase with increasing monitoring frequency (*i.e.*, quarterly monitoring has a higher cost of control than annual monitoring). For EPA Method 21 specifically, the cost also increases with decreasing fugitive emissions repair threshold (*i.e.*, 500 ppm results in a higher cost of control than 10,000 ppm). However, as shown in the TSD, the cost of control based on the OGI methodology for annual, semiannual, and quarterly monitoring frequencies are estimated to be more cost-effective than Method 21 for those same monitoring

[110] U.S. Environmental Protection Agency, Protocol for Equipment Leak Emission Estimates, Table 2–4, November 1995 (EPA–453/R–95–017).

[111] Memorandum to Jodi Howard, EPA/OAQPS from Cindy Hancy, RTI International, Analysis of Emission Reduction Techniques for Equipment Leaks, December 21, 2011. EPA–HQ–OAR–2002–0037–0180

[112] See pages 68–69 of the TSD.

frequencies.[113] We therefore focus our BSER analysis based on the use of OGI.

As shown in the TSD, the costs are comparable for all three monitoring frequencies using OGI. For the reasons explained below, we find the monitoring/repair program using OGI at compressor stations to be cost-effective for all three monitoring frequencies. Under the single pollutant approach, if we assign all control costs to VOC and zero to methane reduction, the costs range from $3,110 to $4,273 per ton of VOC reduced ($2,338 to $3,502 with gas saving) and zero for methane, which indicate that the control is cost-effective. Even if we assign all of the costs to methane and zero to VOC reduction, the costs, which range from $686 to $930 per ton of methane reduced ($471 to $715 per ton with gas savings), are well below our cost-effectiveness estimates for the semi-annual monitoring and repair option for reducing fugitive emissions at compressor stations, which we find to be reasonable for the reasons stated above. Under the multipollutant approach, the costs for VOC reduction range from $1,555 to $2,136 ($1,169 to $1,751 with gas saving). The costs for methane reduction range from $343 to $465 per ton ($236 to $358 per ton with gas savings). Again these cost estimates for methane reductions are well below our estimates for the monitoring/repair program at compressor stations using OGI based on semiannual monitoring, which we find to be reasonable for the reasons stated above. Further, as previously explained, we believe the emission reduction values used in these calculations underestimate the actual emission reductions that would be achieved by a fugitives monitoring and repair program, so these cost of control values likely represent a high end cost assumption. Therefore, we believe the use of OGI is more cost-effective than the amounts presented here. The calculation of the costs, emission reductions, and cost of control calculations for each option are explained in detail in the TSD for this action available in the docket.

While the costs are comparable for all three monitoring frequencies using OGI, for the reasons stated below, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

Further practical aspects we considered for the methodology of each monitoring survey include the likeliness that many owners and operators will hire a contractor to conduct the monitoring survey due to the cost of the specialized equipment needed to perform the monitoring survey and the training necessary to properly operate the OGI equipment. We also believe that small businesses are most likely to hire such contractors because they are less likely to have excess capital to purchase monitoring equipment and train operators. We are concerned that the limited supply of qualified contractors to perform monitoring surveys may lead to disadvantages for small businesses. Larger businesses, due to the economic clout they have by offering the contractors more work due to the higher number of compressor stations they own, may preferentially retain the services of a large portion of the available contractors. This may result in small businesses experiencing a longer wait time to obtain contractor services.

Specifically for conducting OGI monitoring surveys, we believe that many operators will hire OGI contractors to conduct the OGI surveys. The proposed fugitive emissions monitoring plan requires that operators verify the capability of OGI instrumentation, determine viewing distance, and determine the maximum wind speed. Additionally, there are specific requirements for conducting the survey such as how to operate OGI in adverse monitoring conditions or how to deal with interferences such as steam. Each corporate-wide plan will need to include these requirements and will require OGI contractors and operators to be trained to meet these requirement. The monitoring plan requirements will also cause the surveys to take more time, thus affecting the availability of OGI equipment and contractors. Therefore, if we specify quarterly monitoring surveys, we are concerned that the available supply of qualified contractors and OGI instruments may not be sufficient for small businesses to obtain timely monitoring surveys. For the reasons stated above, we have concerns with the potential compliance burdens, in particular on small businesses, associated with quarterly monitoring, and we believe that semi-annual monitoring could achieve meaningful reduction without such potential issues.

We also identified in section VIII.A two additional approaches, based on new capital expenditures and annual revenues, for evaluating whether the costs are reasonable. For monitoring and repair of fugitive emissions at compressor stations, we believe that the total revenue analysis is more appropriate than the capital expenditure analysis and therefore we did not perform the capital expenditure analysis. For the total revenue analysis, we used the revenues for 2012 for NAICS 486210, which we believe is representative of the production segment. The total annualized costs for complying with the proposed standards is 0.103 percent of the total revenues, which is very low.

For all types of affected facilities in the transmission and storage segment, the total annualized costs for complying with the proposed standards is 0.13 percent of the total revenues, which is also very low.

For the reasons stated above, we find the cost of monitoring and repairing fugitive emissions at compressor stations based on semi-annual monitoring using OGI to be reasonable. To ensure that no fugitive emissions remain, a resurvey of the repaired components is necessary. We expect that most of the repair and resurveys are conducted at the same time as the initial monitoring survey while OGI personnel are still on-site. However, there may be some components that cannot be repaired right away and in some instances not until after the initial OGI personnel are no longer on site. In that event, resurvey with OGI would require rehiring OGI personnel, which would make the resurvey not cost effective. On the other hand, as shown in the TSD, the cost of conducting a resurvey using Method 21 is $2 per component, which is reasonable.

We did not find any nonair quality health and environmental impacts, or energy requirements associated with the use of OGI or Method 21 for monitoring, repairing and resurveying fugitive emissions components at compressor stations. Based on the above analysis, we believe that the BSER for reducing fugitive methane and VOC emissions at compressor stations is a monitoring and repair standard based on semi-annual monitoring using OGI and resurvey using Method 21.

Although we identified OGI with semiannual monitoring as the BSER, we acknowledge that some states have promulgated rules that allow for annual monitoring of fugitive emission sources. In addition, EPA regulates GHGs in 40 CFR part 98 subpart W and requires annual fugitive emissions surveys for emissions reporting. As previously discussed we believe that we have underestimated our baseline fugitive emissions estimate for well sites and compressors and the emission reductions may be greater than we have estimated. However, because we continue to support efforts by states to

[113] See the 2015 TSD for full comparison.

establish fugitive emissions monitoring programs and to establish efficiencies across programs, we solicit comment on an alternate option for the fugitive emission monitoring program based on setting the initial monitoring frequency to an annual or quarterly frequency.

CAA section 111(h)(1) states that the Administrator may promulgate a work practice standard or other requirements, which reflects the best technological system of continuous emission reduction when it is not feasible to enforce an emission standard. CAA section 111(h)(2) defines the phrase ''not feasible to prescribe or enforce an emission standard'' as follows:

> [A]ny situation in which the Administrator determines that (A) a hazardous air pollutant or pollutants cannot be emitted through a conveyance designed and constructed to emit or capture such pollutant, or that any requirement for, or use of, such a conveyance would be inconsistent with any Federal, State, or local law, or (B) the application of measurement methodology to a particular class of sources is not practicable due to technological and economic limitations.

The work practice standards for fugitive emissions from compressor stations are consistent with CAA section 111(h)(1)(A), because no conveyance to capture fugitive emissions exist for fugitive emissions components. In addition, OGI does not measure the extent the fugitive emissions from fugitive emissions components. For the reasons stated above, pursuant to CAA section 111(h)(1)(b), we are proposing work practice standards for fugitive emissions from compressor stations.

The proposed work practice standards include details for development of a fugitive emissions monitoring plan, repair requirements and recordkeeping and reporting requirements. The fugitive emissions monitoring plan includes operating parameters to ensure consistent and effective operation for OGI such as procedures for determining the maximum viewing distance and wind speed during monitoring. The proposed standards would require a source of fugitive emissions to be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. We have historically allowed 15 days for repair/resurvey in LDAR programs, which appears to be sufficient time. Further, in light of the number of components at a compressor station and the number that would need to be repaired, we believe that 15 days is also sufficient for conducting the required repairs under the proposed fugitive emission standards. That said, we are also soliciting comment on whether 15 days is an appropriate amount of time for repair of sources of fugitive emissions at compressor stations.[114]

Many recent studies have shown a skewed distribution for emissions related to leaks, where a majority of emissions come from a minority of sources.[115] Commenters on the white papers agreed that emissions from equipment leaks exhibit a skewed distribution, and pointed to other examples of data sets in which the majority of methane and VOC fugitive emissions come from a minority of components (*e.g.*, gross emitters). Based on this information, we solicit comment on whether the fugitive emissions monitoring program should be limited to ''gross emitters.''

We believe that a properly maintained facility would likely detect very little to no fugitive emissions at each monitoring survey, while a poorly maintained facility would continue to detect fugitive emissions. We believe that a facility with proper operation would likely find one to three percent of components to have fugitive emissions. To encourage proper maintenance, we are proposing that the owner or operator may go to annual monitoring if the initial two consecutive semiannual monitoring surveys show that less than one percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. For the same reason, we are proposing that the owner or operator conduct quarterly monitoring if the initial two semi-annual monitoring surveys show that more than three percent of the collection of fugitive emissions components at the compressor station has fugitive emissions. We believe the first year to be the tune-up year to allow owners and operators the opportunity to refine the requirements of their monitoring/repair plan. After that initial year, the required monitoring frequency would be annual if a monitoring survey shows less than one percent of components to have fugitive emissions; semi-annual if one to three percent of total components have fugitive emissions; and quarterly if over three percent of total components have fugitive emissions. We solicit comment on this approach, including the percentage used to adjust the monitoring frequency. We also solicit comment on the appropriateness of performance based monitoring frequencies. We also solicit comment on the appropriateness of triggering different monitoring frequencies based on the percentage of components with fugitive emissions.

Under the proposed standards, the affected facility would be defined as the collection of fugitive emissions components at a compressor station. To clarify which components are subject to the fugitive emissions monitoring provisions, we propose to add a definition to § 60.5430 for ''fugitive emissions component'' as follows:

> Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as a natural gas-driven pneumatic controller or a natural gas-driven pump, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Thus, all fugitive emissions components at the affected facility would be monitored for fugitive emissions of methane and VOC.

For the reasons stated in section VII.G.2, for purposes of the proposed standards for fugitive emission at compressor stations, we propose that a modification occurs only when a compressor is added to the compressor station or when physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station. As explained in that section, since fugitive emissions at compressor stations are from compressors and their associated piping, connections and other ancillary equipment, expansion of compression capacity at a compressor station, either through addition of a compressor or physical change to the an existing compressor, would result in an increase in emissions to the fugitive emissions components. Other than these events, we are not aware of any other physical change to a compressor station that would result in an increase in emissions from the collection of fugitive components at such compressor station. To provide clarity and ease of implementation, for the purposes of the proposed standards for fugitive emissions at compressor stations, we are proposing to define modification as the

[114] This timeline is consistent with the timeline originally established in 1983 under 40 CFR part 60 subpart VV.

[115] See 2015 TSD.

addition of a compressor at an existing compressor station or when a physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

To encourage broadly applied fugitive emissions monitoring, we are also soliciting comments on criteria we can use to determine whether and under what conditions all new or modified compressor stations operating under corporate fugitive monitoring programs can be deemed to be meeting the equivalent of the NSPS standards for compressor stations fugitive emissions such that we can define those regimes as constituting alternative methods of compliance or otherwise provide appropriate regulatory streamlining. We also solicit comment on how to address enforceability of such alternative approaches (*i.e.*, how to assure that these compressor stations are achieving, and will continue to achieve, equal or better emission reduction than our proposed standards).

We are requesting comment on whether the fugitive emissions requirements should apply to all of the fugitive emissions sources at the compressor station for modified compressor stations or just to fugitive sources that are connected to the added compressor. For some modified compressor stations, the added compressor may only be connected to a subset of the fugitive emissions sources on site. We are soliciting comment on whether the fugitive emission requirements should only apply to that subset. However, we are aware that the added complexity of distinguishing covered and non-covered sources may create difficulty in implementing these requirements. However, we note that it may be advantageous to the operator from an operational perspective to monitor all the components at a compressor station since the monitoring equipment is already onsite.

As explained above, Method 21 is not as cost-effective as OGI for monitoring. That said, there may be reasons why and owner and operator may prefer to use Method 21 over OGI. While we are confident with the ability of Method 21 to detect fugitive emissions and therefore consider it a viable alternative to OGI, we solicit comment on the appropriate fugitive emissions repair threshold for Method 21 monitoring surveys. As mentioned above, EPA's recent work with OGI indicates that fugitive emissions at a concentration of 10,000 ppm is generally detectable using OGI instrumentation provided that the right operating conditions (*e.g.*, wind speed and background temperature) are present. Work is ongoing to determine the lowest concentration that can be reliably detected using OGI As mentioned above, we believe that OGI. In light of the above, we solicit comment on whether the fugitive emissions repair threshold for Method 21 surveys should be set at 10,000 ppm or whether a different threshold is more appropriate (including information to support such threshold).

While we did not identify OGI as the BSER for resurvey because of the potential cost associated with rehiring OGI personnel, there is no such additional cost for those who either own the OGI instrument or can perform repair/resurvey at the same time. Therefore, the proposed rule would allow the use either OGI or Method 21 for resurvey. When Method 21 is used to resurvey components, we are proposing that the component is repaired if the Method 21 instrument indicates a concentration of less than 500 ppm above background. This has been historically used in other LDAR programs as an indicator of no detectable emissions.

The proposed standards would require that operators begin monitoring fugitive emissions components at compressor stations with 30 days of the initial startup of a new compressor station or within 30 days of a modification of a compressor station. We are proposing 30 day period to allow owners and operators the opportunity to secure qualified contractors and equipment necessary for the initial monitoring survey. We are requesting comment on whether 30 days is an appropriate amount of time to begin conducting fugitive emissions monitoring.

We received new information indicating that some companies could experience logistical challenges with the availability of OGI instrumentation and qualified OGI personnel to perform monitoring surveys and in some instances repairs. We solicit comment on both the availability of OGI instruments and the availability of qualified OGI personnel to perform monitoring surveys and repairs.

We are requesting comment on whether there are other fugitive emission detection technologies for fugitive emissions monitoring, since this is a field of emerging technology and major advances are expected in the near future. We are aware of several types of technologies that may be appropriate for fugitive emissions monitoring such as Geospatial Measurement of Air Pollutants using OTM–33 approaches (*e.g.,* Picarro Surveyor), passive sorbent tubes using EPA Methods 325A and B, active sensors, gas cloud imaging (*e.g.,* Rebellion photonics), and Airborne Differential Absorption Lidar (DIAL). Therefore, we are specifically requesting comments on details related to these and other technologies such as the detection capability; an equivalent fugitive emission repair threshold to what is required in the proposed rule for OGI; the frequency at which the fugitive emissions monitoring survey should be performed and how this frequency ensures appropriate levels of fugitive emissions detection; whether the technology can be used as a stand-alone technique or whether it must be used in conjunction with a less frequent (and how frequent) OGI monitoring survey; the type of restrictions necessary for optimal use; and the information that is important for inclusion in a monitoring plan for these technologies.

H. Proposed Standards for Equipment Leaks at Natural Gas Processing Plants

In the 2012 NSPS, we established VOC standards for equipment leaks at onshore natural gas processing plants in the oil and natural gas source category. In this action, we are proposing methane standards for onshore natural gas processing plants. Based on the analysis below, the proposed methane standards are the same as the VOC standards currently in the NSPS.

Natural gas is primarily made up of methane. However, whether natural gas is associated gas from oil wells or non-associated gas from gas or condensate wells, it commonly exists in mixtures with other hydrocarbons. These hydrocarbons are often referred to as natural gas liquids (NGL). They are sold separately and have a variety of different uses. The raw natural gas often contains water vapor, H_2S, CO_2, helium, nitrogen and other compounds. Natural gas processing consists of separating certain hydrocarbons and fluids from the natural gas to produced ''pipeline quality'' dry natural gas. While some of the processing can be accomplished in the production segment, the complete processing of natural gas takes place in the natural gas processing segment. Natural gas processing operations separate and recover NGL or other nonmethane gases and liquids from a stream of produced natural gas through components performing one or more of the following processes: Oil and condensate separation, water removal, separation of NGL, sulfur and CO_2 removal, fractionation of natural gas liquid and other processes, such as the capture of CO_2 separated from natural gas streams for delivery outside the facility.

In the analysis for the 2012 NSPS, we estimated nationwide methane emissions from equipment leaks at onshore natural gas processing plants to be 51.4 tpy. We identified four control options for reducing methane emissions from these equipment leaks in the 2012 TSD: (1) Subpart VVa level of control; (2) monthly survey using optical gas imaging (OGI) and an annual Method 21 survey; (3) monthly OGI survey without the annual Method 21 survey; and (4) annual OGI survey.

In April 2014, the EPA published the white paper titled ''Oil and Natural Gas Sector Leaks''[116] which summarized the EPA's current understanding of fugitive emissions of methane and VOC at onshore oil and natural gas production, processing, and transmission and storage facilities. The white paper also outlined our understanding of the available mitigation techniques (practices and equipment) available to reduce these emissions along with the cost and effectiveness of these practices and technologies. Based on our review of the public and peer review comments on the white paper and our additional research, we did not identify any additional control options beyond those that we identified for the 2012 NSPS.

For purposes of this action, we have identified two approaches in section VIII.A for evaluating whether the cost of a multipollutant control, such as the leak detection and repair programs described above, is reasonable. As explained in that section above, we believe that both approaches are appropriate for assessing the reasonableness of the multipollutant controls considered in this action. Therefore, we find the cost of control to be reasonable as long as it is such under either of these two approaches.

Under the first approach (single pollutant approach), which assigns all costs to the reduction of one pollutant and zero to all other pollutants simultaneously reduced, we find the cost of control reasonable if it is reasonable for reducing one pollutant alone. The annualized costs for option 1 (subpart VVa level of control) is $45,160 without considering the cost savings of the recovered natural gas, and $33,915 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $931 per ton. The annualized costs for option 2 (monthly survey using OGI and annual Method 21 survey) is $87,059 without considering the cost savings of the recovered natural gas, and $75,813 considering the cost savings. We estimate the cost of reducing methane emissions from equipment leaks at natural gas processing plants under this option to be $1,795 per ton. At the time of the analysis for the 2012 NSPS, we were unable to estimate the methane emission reduction of options 3 (monthly OGI survey) and 4 (annual OGI survey-only programs) since OGI currently does not have the capability to quantify emissions.

We find the costs for methane emission reductions for option 1 (subpart VVa level of control) to be reasonable for the amount of methane emissions it can achieve. Also, because all of the costs have been attributed to methane reduction, the cost of simultaneous VOC reduction is zero and therefore reasonable.[117]

Although we propose to find the cost of control to be reasonable because it is reasonable under the above approach, we also evaluated the cost of option 1 (subpart VVa level of control) under the second approach (multipollutant approach). Under the second approach, we apportion the annualized cost across the pollutant reductions addressed by the control option in proportion to the relative percentage reduction of each pollutant controlled. In this case, since methane and VOC are controlled equally, half the cost is apportioned to the methane emission reductions and half the cost is apportioned to the VOC emission reductions. Under this approach, the costs are allocated based on the percentage reduction expected for each pollutant. Because option 1 (subpart VVa level of control) reduces the fugitive emission of natural gas from equipment components, emissions of methane and VOC will be reduced equally. Therefore, we attribute 50 percent of the costs to methane reduction and 50 percent to VOC reduction. Based on this formulation, the costs for methane reduction are half of the estimated costs under the first approach above and are therefore reasonable.

With option 1 (subpart VVa level of control) there would be no secondary air impacts, therefore no impacts were assessed. Also, we did not identify any nonair quality or energy impacts associated with this control technique, therefore no impacts were assessed.

In light of the above, we find that the BSER for reducing methane emissions from equipment leaks at natural gas processing plants is a leak detection and repair program at the subpart VVa level of control, and we are proposing to require such a program at natural gas processing plants. As described above, the proposed methane standard would be the same as the current VOC standard for natural gas processing plants in the NSPS.

I. Liquids Unloading Operations

Liquids unloading is an operation that is conducted at natural gas wells to remove accumulated liquids that can impede or even halt production of natural gas due to insufficient gas flow within the wellbore. Fluid accumulation is a common problem in both aging and newer natural gas wells. The typical industry practices used to accomplish liquids unloading include using plunger lifts, beam pumps, remedial treatments, or venting the well to atmosphere (also referred to as blowing down the well). The emissions from liquids unloading result from the intentional venting of gas from the wellbore during activities conducted on or near equipment associated with the removal of accumulated fluids. The volume of gas vented is presumed to be the total volume of gas in the casing and tubing minus the volume of water accumulated in the well. Wells can require multiple unloading events per year; however, the number and frequency of unloading events and volume of emissions generated vary widely. Some wells conduct liquids unloading without venting, through use of closed-loop systems and other technologies.

Based on the information and data available to the EPA during development of the 2012 NSPS, the EPA conducted a preliminary screening of emissions sources with the goal of maximizing emission reductions for new sources. At the time, there was not sufficient data available to determine whether liquids unloading was an issue for hydraulically fractured wells, which represent the majority of projected future production and new sources. In petitions on the 2012 NSPS, some petitioners asserted that the EPA should have regulated the methane and VOC emissions from liquids unloading operations because these emissions are significant and there are data that demonstrate that cost-effective mitigation technologies are available to address the emissions.

Data on liquids unloading operations supplied to the EPA subsequent to the 2012 rule finalization provided significantly better insight into emissions from liquids unloading. Data were provided in a study conducted by members of the American Petroleum

[116] Available at *http://www.epa.gov/airquality/oilandgas/2014papers/20140415leaks.pdf.*

[117] In 2012 we already found that the cost of this control to be reasonable for reducing VOC emissions from natural gas processing plants. We are not reopening that decision in this action.

Institute (API) and America's Natural Gas Alliance (ANGA) and published in a report titled "*Characterizing Pivotal Sources of Methane Emissions from Natural Gas Production, Summary and Analysis of API and ANGA Survey Responses",* hereafter referred to the API/ANGA study, available in the docket. These data demonstrate that venting for liquids unloading can and does result in significant increases in emissions for the well in comparison to wells that do not vent for liquids unloading operations. In addition, data reported to the GHGRP show emissions from venting for liquids unloading similar in magnitude to those calculated using API/ANGA study data.

The 2014 white paper on liquids unloading discussed the most recent information and data available for the analysis of emissions (including the API/ANGA survey and GHGRP data) and industry practices or control technologies available to address these emissions. Commenters on the white paper noted that venting for liquids unloading is a significant source of emissions and that these emissions are highly skewed, with a minority of sources being responsible for a large fraction of total emissions. As a result, commenters urged the EPA to further study these operations and that regulation of those operations at this time would be premature.

Since publication of the white paper, additional data have become available on liquids unloading emissions from Allen et al., 2014. The Allen *et al.* data confirm the findings of previous studies, that venting for liquids unloading is a significant source of emissions and that emissions are highly skewed. Data reviewed also show that liquids unloading events are highly variable and often well-specific. Furthermore, questions remain concerning the difficulty of effective control for these high-emitting events in many cases and the applicability and limitations of specific control technologies such as plunger lift systems for supporting a new source performance standard. For analysis conducted in the development of this proposal, we revised our estimate of methane and VOC emissions from liquids unloading based on the API/ANGA study data and Allen *et al.* Based on the emissions data discussed in the white paper, and on new data available from Allen *et al.,* we believe that the emissions from liquids unloading operations are significant. However, as noted in section VII.I, the EPA does not have sufficient information to propose standards for liquids unloading. The EPA is continuing to study this issue and is soliciting information and data on control technologies or practices for reducing these emissions.

Specifically, we are soliciting comment on the level of methane and VOC emissions per unloading event, the number of unloading events per year, and the number of wells that perform liquids unloading. In addition, we solicit comment on (1) characteristics of the well that play a role in the frequency of liquids unloading events and the level of emissions, (2) demonstrated techniques to reduce the emissions from liquids unloading events, including the use of smart automation, and the effectiveness and cost of these techniques, (3) whether there are demonstrated techniques that can be employed on new wells that will reduce the emissions from liquids unloading events in the future, and (4) whether emissions from liquids unloading can be captured and routed to a control device and whether this has been demonstrated in practice.

IX. Implementation Improvements

A. Storage Vessel Control Device Monitoring and Testing Provisions

We are proposing regulatory text changes that address performance testing and monitoring of control devices used for new storage vessel installations and centrifugal compressor emissions, specifically relating to in-field performance testing of enclosed combustors. Industry reconsideration petitioners assert that the compliance demonstration and monitoring requirements finalized in the 2012 NSPS were overly complex and stringent given the large number of affected storage vessels each year and the remoteness of the well sites at which they are installed. The petitioners argue that the well sites are unmanned for periods of time up to a month. The additional information provided by petitioners raised significant concerns that the compliance monitoring provisions and field testing provisions of the 2012 NSPS may not have been appropriate for the large number of affected storage vessels, which was much greater than we had expected, and of which many are in remote locations.

In the reconsideration of the NSPS that was finalized in 2013, we streamlined certain monitoring and continuous compliance demonstration requirements, while we more fully evaluated the proper requirements. Instead of the detailed Method 21 monitoring requirements, the revised requirements included monthly sensory (*i.e.,* OVA) inspections of: (1) Closed-vent system joints, seams and other sealed connections (*e.g.,* welded joints); (2) other closed-vent system components such as peak pressure and vacuum valves; and (3) the physical integrity of tank thief hatches, covers, seals and pressure relief devices. Instead of the continuous parameter monitoring system (CPMS) requirements, the revised requirements included the following inspection requirements: (1) Monthly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 15 minute period; (2) monthly visual inspection of the physical integrity of the control device; and (3) monthly check of the pilot flame and signs of improper operations. Lastly, instead of the field performance testing requirements in § 60.5413, we required that, where controls are used to reduce emissions, sources use control devices that by design can achieve 95 percent or more emission reduction and operate such devices according to the manufacturer's instructions, procedures and maintenance schedule, including appropriate sizing of the combustor for the application.

After evaluating these streamlined requirements and other potential options, we believe that performance testing of enclosed combustors is necessary to assure that they are achieving the required 95 percent control. However, petitioners also assert that the previous performance testing requirements were unreasonably strenuous for a control device needing to demonstrate 95 percent control efficiency. They assert that in order for an enclosed combustor to meet a requirement of 20 parts per million volume (ppmv) it would have to be achieving greater than the required 95 percent control. After an evaluation of the requirement we agree with the comment and are proposing to revise this requirement from 20 ppmv to 600 ppmv; a value that more appropriately reflects 95 percent control of VOC inflow to these control devices. The EPA solicits comment on the appropriateness of this level of control and invites commenters to provide data that demonstrates the VOC composition of field gas from a variety of oil and gas field well sites across the nation.

As proposed, initial and ongoing performance testing will be required for any enclosed combustors used to comply with the emissions standard for an affected facility and whose make and model are not listed on the EPA Oil and Natural Gas Web site (*http://www.epa.gov/airquality/oilandgas/implement.html*) as those having already met a Manufacturer's Performance Test demonstration. Performance testing of combustors not listed at the above site would also be conducted on an ongoing basis, every 60 months of service, and monthly monitoring of visible emissions from each unit is also required.

We are proposing amendments to make the requirements for monitoring of visible emissions consistent for all enclosed combustion units. Currently enclosed combustors that have met the Manufacturer's Performance Test requirement must conduct quarterly observation for visible smoke emissions employing section 11 of EPA Method 22 for a 60 minute period. 40 CFR 60.5413(e)(3). Certain petitioners have suggested it may ease implementation to adjust the frequency and duration to monthly 15 minute EPA Method 22 tests, which is currently required for continuous monitoring of enclosed combustors that are not manufacturer tested. 40 CFR 60.5417(h)(1). If this change were made then all enclosed combustors would have the same monitoring requirements which could potentially make compliance easier for owners and operators. Because both monitoring requirements assure compliance of the enclosed combustors, and having the same requirement would ease implementation burden, we propose to amend 40 CFR 60.5413(e)(3) to require monthly 15 minute-period observation using EPA Method 22 Test, as suggested by the petitioner.

B. Other Improvements

Following publication of the 2012 NSPS and the 2013 storage vessel amendments, we subsequently determined, following review of reconsideration petitions and discussions with affected parties, that the final rule warrants correction and clarification in certain areas. Each of these areas is discussed below.

1. Initial Compliance Requirements for Bypass Devices

Initial compliance requirements in § 60.5411(c)(3)(i)(A) for a bypass device that could divert an emission stream away from a control device were previously amended to allow for initiating a notification via remote alarm to the nearest field office indicating that the bypass device was activated. However, the previous amendments did not address parallel requirements for continuous compliance in § 60.5416. In order to maintain consistency with the previously amended § 60.5411, we are proposing to amend § 60.5416(c)(3)(i) to include notification via remote alarm to the nearest field office. We are proposing to require both an alarm at the bypass device and a remote alarm. This is important in this source category due to the great number of unmanned sites, especially well sites. Previously, the only option was an alarm at the device location. We believe this change will ensure that personnel will be alerted to a potential uncontrolled emissions release whether they are in the vicinity of the bypass device when it is activated or at a remote monitoring location. Finally, we are proposing similar amendments to parallel requirements at § 60.5411(a)(3)(i)(A) for closed vent systems used with reciprocating compressors and centrifugal compressor wet seal degassing systems.

2. Recordkeeping Requirements

Petitioners noted that the recordkeeping requirements of § 60.5420(c) do not include the repair logs for control devices failing a visible emissions test required by § 60.5413(c). We agree that these recordkeeping requirements should be listed and are proposing to add them at § 60.5420(c)(14).

3. Due Date for Initial Annual Report

Petitioners pointed out that the preamble to the 2013 final rule stated that the initial annual report is due on January 15, 2014; however, § 60.5420(b) states that initial annual report is due 90 days after the end of the initial compliance period. The petitioners correctly contend that this equates to a due date of January 13, 2014. Although we inadvertently stated a date three months after the end of the initial compliance period (rather than 90 days after) in the preamble, we are not proposing to amend the rule at this time. Rather, we will consider any initial annual report submitted no later than January 15, 2014 to be a timely submission. All subsequent annual reports must be submitted by the correct date of January 13 of the year.

4. Flare Design and Operation Standards

The petitioners requested that the EPA clarify the regulatory compliance requirements for storage vessel affected facilities with respect to flares. Currently subpart OOOO contains conflicting references to the NSPS general provisions that obscures the EPA's intent to require compliance with the requirements for the design and operation of flares under § 60.18 of the General Provisions. To clarify EPA's intent, the EPA is proposing to remove the provision of Table 3 in subpart OOOO that exempts flares from complying with the requirements for the design and operation of flares under 40 CFR 60.18 of the General Provisions. By removing the exemption from the General Provisions from subpart OOOO, this clarifies that flares used to comply with subpart OOOO are subject to the design and operation requirements in the general provisions.

It has recently come to EPA's attention that that there may be affected facilities which use pressure assisted-flares (e.g., sonic flares) to control emissions during periods of startup, shutdown, emergency and/or maintenance activities. While compliance with the NSPS emission limits can be achieved using such flares, when designed and operated properly, it is EPA's understanding that pressure-assisted flares cannot meet the maximum exit velocity of 400 feet per second as required by 40 CFR 60.18(b). Pressure-assisted flares are designed to operate with a high velocities up to sonic velocity conditions (*e.g.*, 700 to 1,400 feet per second) for common hydrocarbon gases.

In order to evaluate the use of pressure-assisted flares by the oil and natural gas industry and determine whether to develop operating parameters for pressure-assisted flares for purposes of subparts OOOO (and subpart OOOOa should it be finalized), the EPA is soliciting comment on where in the source category, under what conditions (*e.g.*, maintenance), and how frequently pressure-assisted flares are used to control emissions from an affected facility, as defined within this subpart. In addition, we request information on: (1) The importance of, and assessment of flame stability; (2) the importance of, and ranges of the heat content of flared gas; (3) the importance and ranges of gas pressure and flare tip pressure; (4) the importance of and examples of appropriate flare head design; (5) a cross-country review of waste gas composition; (6) and appropriate methodology to measure the resultant flare destruction efficiency. The EPA also requests comment on the appropriate parameters to monitor to ensure continuous compliance. This information is critical for the potential development of operating parameters for pressure-assisted flares given the limited to no information currently available for this type of flare in the oil and natural gas industry.

5. Exemption to Notification Requirement for Reconstruction

The petitioners asked for the EPA to consider whether a single remaining notification of reconstruction required under § 60.15(d) of the General Provisions was necessary, given that the EPA had already provided an exemption to parallel requirements for construction, startup, and modification. The EPA agrees with the petitioner that the notification of reconstruction requirements under § 60.15(d) is unnecessary. The EPA considers it unnecessary because subpart OOOO specifies notification of reconstruction for affected unit pneumatic controllers, centrifugal compressors, and storage vessels under § 60.5410 and § 60.5420 in lieu of the general notification requirement in § 60.15(d). The EPA, therefore, proposes to add in Table 3 that § 60.15(d) does not apply to affected facility pneumatic controllers, centrifugal compressors, and storage vessels subject to subpart OOOO.

6. Disposal of Carbon From Control Devices

We are re-proposing the provisions for management of waste from spent carbon canisters that were finalized in § 60.5412(c)(2) of the 2012 NSPS to allow for comment. Petitioners assert that the requirements for RCRA-level management of waste from spent carbon canisters are unnecessary and overly burdensome. Further, they assert that those provisions were not in the proposal which excluded them from review and comment. We do not agree that these provisions are overly burdensome because RCRA hazardous waste units are not the only options made available to manage the spent carbon. In the scenario where the carbon is to be burned, the EPA sought a means to assure that sufficient precaution was taken to assure complete destruction of the carbon and adsorbed compounds. These same requirements apply to spent carbon from units subject to NESHAP subpart HH in oil and natural gas production, further supporting our decision to seek consistent and appropriate levels of control for burning spent carbon from an adsorption system. We are re-proposing the provisions here to allow for review and comment. Petitioners may submit alternatives that would allow for consistent treatment of spent carbon from the oil and natural gas sector, and that assure destruction of the compounds adsorbed in carbon adsorption control units.

7. Definition of Capital Expenditure

Petitioners requested that the EPA clarify the definition of ''capital expenditure'' in subpart OOOO. The term is used in section § 60.5365(f), which describes the applicability of the equipment leaks provisions for onshore natural gas processing plants. Specifically, 40 CFR 60.5365(f)(1) states that ''addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.'' Subpart OOOO does not define ''capital expenditure'' but states in 40 CFR 60.5430 (definition section) that ''all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60.'' The term ''capital expenditure'' is defined in the General Provisions subpart A, as well as in subpart VVa. However, this definition in subpart VVa is currently stayed. The EPA agrees with the commenter that this capital expenditure approach applies to onshore natural gas processing plants that are subject to subpart OOOO. The EPA had previously adopted this method for determining modification in subpart KKK. In fact, the capital expenditure provision in subpart OOOO, 40 CFR 60.5365(f)(1) was carried over from subpart KKK 40 CFR 60.630(c). Subpart KKK does not specifically define ''capital expenditure;'' it states in 40 CFR 60.631 that ''as used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VV of part 60. . .'' This means that the definition of capital expenditure in subpart KKK is the current definition in VV.

In conducting the EPA's 8-year review of subpart KKK, the EPA promulgated subpart OOOO, which includes certain revisions to subpart KKK. The EPA revised the existing NSPS requirements for LDAR to reflect the procedures and leak definition established by 40 CFR part 60, subpart VVa (77 FR 49498). Specifically, the revision to subpart KKK, which is codified in subpart OOOO, includes a lower leak definitions for valves and pumps and requires monitoring of connectors.

The EPA's 8-year review and revision of subpart KKK did not include any change to the capital expenditure provision as it applies to oil and natural gas processing plants. This means that the technique used to determine whether there is a modification based on capital expenditure under OOOO remains the same technique as in subpart KKK (*i.e.*, based on the definition of ''capital expenditure'' in subpart VV).

However, as the petitioner correctly noted, the year that is the basis for calculating Y (the percent of replacement cost) is designed to reflect the year of the proposed standards for the relevant subpart at issue; as such, the definition of ''capital expenditure'' in subpart VV does not reflect the year subpart OOOO was proposed (*i.e.*, 2011) and is therefore inaccurate for application to subpart OOOO as is. To address this issue, the EPA is proposing to provide in subpart OOOO a definition for ''capital expenditure'' that essentially mirrors [118] the definition in subpart VV but with the year revised to reflect the year subpart OOOO was proposed (*i.e.*, 2011).

The EPA disagrees with the petitioner that the appropriate applicable basic annual asset guideline repair allowance, designated ''B'' in the formula, is 12.5, which is the B value for Subpart VVa. Since ''capital expenditure'' method was not among the updates the EPA made in its review of the subpart KKK (and subpart OOOO is the updated version of KKK), the allowance in KKK (*i.e.*, 4.5 according to subpart VV) remains applicable to onshore gas affected facilities. Further, B values are based on the annual asset guideline repair allowance specified in IRS Revenue Procedure 83–35. The specified allowance value is 4.5 for exploration and production of petroleum and natural gas deposits. Also, as evident from the ''capital expenditure'' definitions in both subparts VV and VVa, the B values are subpart-specific and therefore the EPA has promulgated specific B values for different subparts. Whereas subpart VV includes a specific B value for natural gas processing plants covered by subpart KKK (natural gas processing plants), there is no such value in subpart VVa referencing subpart KKK. For the reasons stated above, the EPA clarifies that the B value for purposes of subpart OOOO is 4.5; it is not 12.5, as the petitioner suggests.

In sum, to provide clarity the EPA is proposing to specifically define the term ''capital expenditure'' in subpart OOOO. In this proposed definition, EPA is updating the formula to reflect the calendar year that subpart OOOO was proposed, as well as specifying that the B value for subpart OOOO is 4.5. These updates are necessary for proper calculation of capital expenditure under subpart OOOO.

8. Initial Compliance Clarification

An issue was raised in an administrative petition that EPA did not adequately respond to a comment on the 2011 proposed NSPS regarding compliance period for the LDAR requirements for On-Shore Natural Gas Processing Plants. The comment at issue [119] requested that EPA include in

[118] The proposed definition does not include B values listed in subpart VV for other subparts because those values are irrelevant to subpart OOOO.

[119] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air

Continued

subpart OOOO a provision similar to subpart KKK, 40 CFR 60.632(a), which allows a compliance period of up to 180 days after initial start-up. The commenter was ''concerned that a modification at an existing facility or a subpart KKK regulated facility could subject the facility to Subpart OOOO LDAR requirements without adequate time to bring the whole process unit into compliance with the new regulation.'' [120]

We clarify that subpart OOOO, as promulgated in 2012, already includes a provision similar to subpart KKK, § 60.632(a), as requested in the comment. Specifically, § 60.5400(a) requires compliance with 40 CFR 60.482–1a(a), which provides that ''[e]ach owner or operator subject to the provisions of this subpart shall demonstrate compliance . . . within 180 days of initial startup.'' This provision applies to all new, modified, and reconstructed sources. With respect to modification, which was of specific concern to the commenter, a change to a unit sufficient to trigger a modification and thus application of the subpart OOOO LDAR requirements for on-shore natural gas processing plants would be followed by startup, which would mark the beginning of the 180 day compliance period provided in 40 CFR 60.482–1a(a) (incorporated by reference in subpart OOOO § 60.5400(a)).

9. Tanks Associated With Water Recycling Operations

In many cases, flowback water from well completions and water produced during ongoing production is collected, treated and recycled to reduce the volume of potable water withdrawn from wells or other sources. Large, non-earthen tanks are used to collect the water for recycling following separation to remove crude oil, condensate, intermediate hydrocarbon liquids and natural gas. These collection tanks used for water recycling are very large vessels having capacities of 25,000 barrels or more, with annual throughput of millions of barrels of water. In contrast, industry standard storage vessels commonly found in well site tank batteries and used to contain crude oil, condensate, intermediate hydrocarbon liquids and produced water typically have capacities in the 500 barrel range.

In the 2012 NSPS, we had envisioned the storage vessel provisions as regulating the vessels in well site tank batteries and not these large tanks primarily used for water recycling. It was never our intent to cover these large water recycling tanks. It recently came to our attention that these water recycling tanks could be inadvertently subject to the NSPS due to the extremely low VOC content combined with the millions of barrels of throughput each year, which could result in a potential to emit VOC exceeding the NSPS storage vessel threshold of 6 tpy.[121] The EPA encourages efforts on the part of owners and operators to maximize recycling of flowback and produced water. We are concerned that the inadvertent coverage of these tanks under the NSPS could discourage recycling. It is our understanding that, due to the size and throughput of these tanks, combined with the trace amounts of VOC emissions that are difficult to control, that operators may choose to discontinue recycling to avoid noncompliance with the NSPS.

As a result, we are considering changes in the final rule to remove tanks that are used for water recycling from potential NSPS applicability. We solicit comment on approaches that could be taken to amend the definition of ''storage vessel'' or other changes to the NSPS that would resolve this issue without excluding storage vessels appropriately covered by the NSPS. In addition, we solicit comment on location, capacity or other criteria that would be appropriate for such purpose.

X. Next Generation Compliance and Rule Effectiveness

A. Independent Third-Party Verification

The EPA is taking comment on establishing a third-party verification program as discussed below. Third-party verification is when an independent third-party verifies to a regulator that a regulated entity is meeting one or more of its compliance obligations. The regulator retains the ultimate responsibility to monitor and enforce compliance but, as a practical matter, gives significant weight to the third-party verification provided in the context of a regulatory program with effective standards, procedures, transparency and oversight. While requiring regulated entities to monitor and report should improve compliance by establishing minimum requirements for a regulated entity's employees and managers, well-structured third-party compliance monitoring and reporting may further improve compliance.

The third-party verification program would be designed to ensure that the third-party reviewers are competent, independent, and accredited, apply clear and objective criteria to their design plan reviews, and report appropriate information to regulators. Additionally, there would need to be mechanisms to ensure regular and effective oversight of third-party reviewers by the EPA and/or states which may include public disclosure of information concerning the third parties and their performance and determinations, such as licensing or registration.

The EPA is considering a broad range of possible design features for such a program under the following two scenarios: (A) Third-Party Verification of Closed Vent System Design and (B) Third-Party Verification of IR Camera Fugitives Monitoring Program. These include those discussed or included in the following articles, rules, and programs:

(1) Lesley K. McAllister, Regulation by Third-Party Verification, 53 B.C. L. REV. 1, 22–23 (2012);

(2) Lesley K. McAllister, THIRD–PARTY PROGRAMS FINAL REPORT (2012) (prepared for the Administrative Conference of the United States), available at *http://www.acus.gov/report/third-party-programs-final-report;*

(3) Esther Duflo *et al.,* Truth-Telling By Third-Party Auditors and the Response of Polluting Firms: Experimental Evidence From India, 128 Q. J. OF ECON. 4 at 1499–1545 (2013);

(4) EPA CAA Renewable Fuel Standard (RFS) program: The RFS regulations include requirements for obligated parties to, in relevant part, submit independent third-party engineering reviews to the EPA before generating Renewable Identification Numbers (RINs).[122]

(5) Massachusetts Underground Storage Tank (UST) third-party inspection program: The owners/operators of most underground storage tanks in Massachusetts are required to have their USTs inspected by third-party inspectors every three years. While the third-party inspectors are hired directly by the tank owners and operators, they report to the Massachusetts Department of Environmental Protection (MassDEP). The third parties conduct and document detailed inspections of USTs and piping systems, review facility recordkeeping to ensure it meets UST program requirements, and submit reports on their findings electronically to MassDEP.[123]

Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 3, 32–33.

[120] Comments of the Gas Processors Association Regarding the Proposed Rule, Oil and Natural Gas Sector: New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants Reviews, 76 FR 52738 (Aug. 23, 2011). Pp. 33.

[121] Letter from Obie O'Brien, Vice President—Government Affairs/Corporate Outreach, Apache Corporation, to EPA Docket, Docket ID Number EPA–HQ–OAR–2010–4755, April 20, 2015. Similar letters from Rockwater Energy Solutions (EPA–HQ–OAR–2010–4756) and Permian Basin Petroleum Association (EPA–HQ–OAR–2010–4757).

[122] EPA, Renewable Fuel Standards (RFS), *http://www.epa.gov/OTAQ/fuels/renewablefuels/.*

[123] MassDEP, Third-Party Underground Storage Tank (UST) Inspection Program, *http://*

(6) Massachusetts licensed Hazardous Waste Site Cleanup Professional program: Private parties who are financially responsible under Massachusetts law for assessing and cleaning up confirmed and suspected hazardous waste sites must retain a licensed Hazardous Waste Site Cleanup Professional (commonly called a ''Licensed Site Professional'' or simply an ''LSP'') to oversee the assessment and cleanup work.[124]

We have identified one potential area for third-party verification under this rule.

Professional Engineer Certification of Closed Vent System and Control Device Design and Installation

When produced liquids from oil and natural gas operations are routed from the separator to the condensate storage tank, a drop in pressure from operating pressure to atmospheric pressure occurs. This results in ''flash emissions'' as gases are liberated from the condensate stream due to the change in pressure. The magnitude of flash emissions can dwarf normal working and breathing losses of a storage tank. If the control system (closed vent system and control device, including pressure relief devices and thief hatches on storage vessels) cannot accommodate the peak instantaneous flow rate of flash emissions, working losses, breathing losses and any other additional vapors, this may cause pressure relief devices and thief hatches to ''pop'' and they may not properly reseat, resulting in immediate and potentially continuing excess emissions. Through our energy extraction enforcement initiative, we have seen this to be the case, due in large part to undersized control systems that may have been inadequately designed to accommodate only working and breathing losses of a storage tank. We have worked in conjunction with states, including Colorado, in conducting inspection campaigns associated with storage vessels. In two inspection campaigns, in two different regions, we recorded venting from thief hatches or other parts of the control system at over 60 percent of the tank batteries inspected. Another inspection campaign resulted in a much higher leak rate, with 23 of 25 tank batteries experiencing fugitive emissions.

One potential remedy for the inadequate design and sizing of the closed vent system would be to require an independent third-party (independent of the well site owner/operator and control device manufacturer), such as a professional engineer, to review the design and verify that it is designed to accommodate all emissions scenarios, including flash emissions episodes. Another element of the professional engineer verification could be that the professional engineer verifies that the control system is installed correctly and that the design criteria is properly utilized in the field.

Another approach to detecting overpressure in a closed vent system would be to require a continuous pressure monitoring device or system, located on the thief hatches, pressure relief devices and other bypasses from the closed vent system. Through our inspections, we have seen thief hatch pressure settings below the pressure settings of the storage tanks to which they are affixed. This results in emissions escaping from the thief hatch and not making it to the control device.

The EPA requests comment on these approaches. Specifically, we request comment as to whether we should specify criteria by which the PE verifies that the closed vent system is designed to accommodate all streams routed to the facility's control system, or whether we might cite to current engineering codes that produce the same outcome. We also request comment as to what types of cost-effective pressure monitoring systems can be utilized to ensure that the pressure settings on relief devices is not lower than the operating pressure in the closed vent to the control device and what types of reporting from such systems should be required, such as through a supervisory control and data acquisition (SCADA) system.

B. Fugitives Emissions Verification

As discussed in sections VII.G and VIII.G, the EPA is proposing the use of OGI as a low cost way to find leaks. While we believe we are proposing a robust method to ensure that OGI surveys are done correctly, we have ample experience from our enhanced leak detection and repair (LDAR) efforts under our Air Toxics Enforcement Initiative, that even when methods are in place, routine monitoring for fugitives may not be as effective in practice as in design. Similar to the audits included as part of consent decrees under the Initiative (*See U.S. et. Al.* v. *BP Products North America Inc.),* we are soliciting comment on an audit program of the collection of fugitive emissions components at well sites and compressor stations.

For this rule, we are anticipating a structure in which the facilities themselves are responsible for determining and documenting that their auditors are competent and independent pursuant to specified criteria. The Agency seeks comment as to whether this approach is appropriate for the type of auditing we describe below, or whether an alternative approach, such as requiring auditors to have accreditation from a recognized auditing body or EPA, or other potentially relevant and applicable consensus standards and protocols (*e.g.*, American National Standards Institute (ANSI), ASTM International (ASTM), European Committee for Standardization (CEM), International Organization for Standardization (ISO), and National Institute of Standards and Technology (NIST) standards), would be preferable.

In order to ensure the competence and independence of the auditor, certain criteria should be met. Competence of the auditor can include safeguards such as licensing as a Professional Engineer (PE), knowledge with the requirements of rule and the operation of monitoring equipment (*e.g.*, optical gas imaging), experience with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and training or certification in auditing techniques.

Independence of the auditor can be ensured by provisions and safeguards in the contracts and relationships between the owner and operator of the affected facility with auditors. These can include: The auditor and its personnel must not have conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years; the auditor and its personnel must not provide other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report; and all auditor personnel who conduct or otherwise participate in the audit must sign and date a conflict of interest statement attesting the personnel have met and followed the auditors' policies and procedures for competence, impartiality, judgment, and operational integrity when auditing under this section; and must receive no financial benefit from the outcome of the Audit, apart from payment for the auditing services themselves. In addition, owners or operators cannot provide future employment to any of the auditor's personnel who conducted or otherwise participated in the Audit for a period of at least 3 years following the Auditor's submittal of its final Audit report and must be empowered to direct

www.mass.gov/eea/agencies/massdep/toxics/ust/third-party-ust-inspection-program.html.

[124] *http://www.mass.gov/eea/agencies/massdep/cleanup/licensed-site-professionals.html.*

their auditors to produce copies of any of the audit-related reports and records specified in those sections. Both the owners and operators and their auditors should sign supporting certifications statements. To further minimize audit bias, an audit structure might require that audit report drafts and final audit reports be submitted to EPA at the same time, or before, they are provided to the owners and operators. Furthermore, the audits conducted by the auditors under this rule should not be claimed as a confidential attorney work products even if the auditors are themselves, or managed by or report to, attorneys.

There may be other options, in addition to the approaches above, that may increase owner or operator flexibility, but these options also present risks of introducing bias into the program, resulting in less robust and effective audit reports. EPA invites comment on the structure above as well as alternative auditor/auditing approaches with less rigorous independence criteria. For example, EPA could, in the final rule, allow for audits to be performed by auditors with some potential conflicts of interest (*e.g.*, employees of parent company, affiliates, vendors/contractors that participated in developing source master plan(s) and/or site-specific plan(s), etc.) and/or allow a person at the facility itself who is a registered PE or who has the requisite training in conducting optical gas imaging monitoring to conduct the audit. If such approaches are adopted in the final rule, the Agency could seek to place appropriate restrictions on auditors and auditing with less than full independence from their client facilities in an effort to increase confidence that the auditors will act accurately when performing their activities under the rule. Such provisions could include ones addressed to ensuring that auditor personnel who assess a facility's compliance with the fugitives monitoring requirements do not receive any financial benefit from the outcome of their auditing decisions, apart from their basic salaries or remuneration for having conducted the audits.

Additional examples of the types of restrictions that could be placed on such self-auditing to potentially improve auditor impartiality and auditing outcomes appear in the U.S. and CARB v. Hyundai Motor Company, et al. Consent Decree (CD). Until the CDs corrective measures are fully implemented, the defendants must audit their fleets to ensure that vehicles sold to the public conform to the vehicles' certification. The CD provides that the audit team will be in the United States, will be independent from the group that performed the original certification work, and must perform their audits without access to or knowledge of the defendants' original certification test data which the CD-required audits are intended to backcheck. EPA seeks comment as to whether similar restrictions could be effective for any potential enhanced self-auditing conducted under the rule.

Finally, EPA seeks comment on whether, and to what extent, the public should have access to the compliance reports, portions or summaries of them and/or any other information or documentation produced pursuant to the auditing provisions. EPA is also considering the approach it should take to balance public access to the audits and the need to protect Confidential Business Information (CBI). To balance these potentially competing interests, EPA is reviewing a variety of approaches that may include limiting public access to portions of the audits and/or posting public audit grades or scores to inform the public of the auditing outcomes without compromising confidential or sensitive information. EPA seeks comment on these transparency and public access to information issues in the context of the proposed auditing provisions.

A suggested structure which incorporates concepts from the discussion above, and relevant to an audit of the fugitives monitoring program of the collection of fugitive emissions components at well sites and compressor stations could include the following structure:

Within the first year of applicability to the rule, an OGI trained auditor, experienced with the facility type and processes being audited and the applicable recognized and generally accepted good engineering practices, and trained or certified in auditing techniques, and who has not:

a. served as a fugitive emissions monitoring technician at the source,

b. conducted past research, development, design, construction services, or consulting for the owner or operator within the last 3 years or;

c. provided other business or consulting services to the owner or operator, including advice or assistance to implement the findings or recommendations in the Audit report, for a period of at least 3 years following the Auditor's submittal of the final Audit report;

shall:

a. Verify that the source has established a master and site specific monitoring plan;

b. Verify that the master and site specific monitoring plan includes the elements described in the rule;

c. Verify that the fugitive components were monitored in accordance with the master and site specific monitoring plan and at the appropriate frequency under the plan(s) and the rule;

d. Verify that proper documentation and sign offs have been recorded for all fugitive components placed on the delay of repair list;

e. Ensure that repairs have been performed in the required periods under the rule;

f. Review monitoring data for feasibility (*e.g.*, do the survey results reflect a feasible timeframe in which to conduct the monitoring survey) and unusual trends;

g. Verify that proper calibration records and monitoring instrument maintenance information are maintained;

h. Verify that other fugitives emissions monitoring records are maintained as required; and

i. Observe in the field each technician who is conducting fugitive emissions monitoring to ensure that monitoring is being conducted as described in the rule and the master and site specific plan;

j. Submit a report to the EPA and the facility outlining the findings of the audit with deficiencies and corrective actions provided.

k. Sign a certification statement that the report was prepared by the auditor conducting the audit (or under his/her direction or supervision), that the report is true, accurate, and complete, that the Audit was prepared pursuant to, and meets the requirements of, 40 CFR part 60 subpart OOOOa, and any other applicable auditing, competency, and independence/impartiality/conflict of interest standards and protocols.

Upon the receipt of the auditor's report, the source should correct any deficiencies detected or observed within four months. The source would be required to maintain a record that: (i) Records the auditor's report; and (ii) describes the nature and timing of any corrective actions taken. The source would be required to submit in their periodic compliance report, a summary of the findings of the auditor's report and a description and timing of any corrective actions taken. EPA envisions that the audit would be repeated with some frequency and requests comment on the appropriate frequency, and any actions, trends or compliance triggers which might require or allow deviation from the frequency.

C. Third-Party Information Reporting

Third-party information reporting occurs when a third-party reports information on a regulated source's performance, directly to the regulator. To promote improved compliance, third-party information reporting reduces information asymmetries between what the regulated entities know about themselves and the regulators' knowledge about the entities.

An example of third-party information reporting involves federal income tax law where certain income must be independently reported to the Internal Revenue Service (IRS) by payers of the income. Because the information is required to be identical to that reported by taxpayers, the government can compare the dual disclosures for consistency. Taxpayers know this and are deterred from failing to report or underreporting.

We outlined a potential third-party information reporting structure for oil and natural gas in our 2013 proposed amendments. We continue to believe that application of such a reporting structure is a natural outgrowth for implementation of the manufacturer performance testing requirements under subpart OOOO and subparts HH/HHH. As previously discussed in the 2013 proposal, an owner or operator that purchases a specific model of control device that the manufacturer has demonstrated achieves the combustion control device performance requirements in NSPS subpart OOOO (a ''listed device'') is exempt from conducting their own performance test and submitting performance test results. To provide further incentive to use such a listed device, the EPA can ''level the playing field'' by ensuring that exemption claims are valid. Using the framework of third-party information reporting, the owner or operator would demonstrate initial compliance by providing proof of purchase of the listed device, reporting certain information, such as device model, serial number, geospatial coordinates and date of installation in their annual report following the end of the compliance period during which the device was installed. In the final rule, the EPA could conceivably supplement the owner/operator reporting requirement with a manufacturer reporting requirement providing the names of entities that had purchased the listed device. The manufacturer report to the EPA could be very simple, such as a ''notice and go'' or ''post card'' type report. This could allow a simple cross check of the owner's or operator's report with the manufacturer's sales confirmation, making compliance checks easy and provide assurance to the Agency that the source has in fact purchased and installed a manufacturer performance tested device, improving compliance with the rule.

As noted above, we have currently evaluated and posted 15 enclosed combustor models, allaying concerns that it would take ''years of work'' to avoid compliance complications with the process. The EPA continues to encourage the option to use listed devices and believe that operators have an incentive to do so, in lessened initial and on-going compliance demonstration costs. Third-party information reporting could lessen any lingering concerns with implementation and potential compliance complications. However, we understand the issues for this sector, with making the ''postcard'' model work as we envisioned. One of the issues is related to the granularity of the reporting by the manufacturer as compared to the reporting by the source to the EPA or delegated authority. For example, the manufacturer may only know that they sold 500 units of a particular control device, but may not know where it is actually installed. Lack of a unique ''user ID'' being reported by both sides can limit the utility of the postcard model in this instance. We solicit comment on potential third-party approaches such as the ''post card'' reporting described above that could be implemented to streamline and enhance compliance.

As stated above, a primary concern is that an owner or operator would install a control device, and not conduct a performance test, claiming that they installed a device listed on the Oil and Gas page. We believe that we can build on the success of GIS imbedded digital photos for green completions (''REC PIX''), already in the rule, by developing a similar requirement for installed manufacturer tested control devices. Enhancing the records and reports by requiring specifics of the control device (make, model and serial number) and requiring the digital picture, will allow us to match a particular control device at a specific location with control device models listed on the Oil and Gas page.[125] Having this information electronically reported to CEDRI will further enhance our ability to evaluate compliance with the rule.

While we are soliciting comment on third-party reporting by combustor vendors directly to the EPA, we propose to require that owners or operators include information regarding purchase of a pre-tested combustor model in their Notice of Compliance Status as part of the first annual report following the compliance period in which the combustor commences operation. The information would include (1) make, model and serial number of the purchased device; (2) date of purchase; (3) inlet gas flow rate; (4) latitude and longitude of the emission source being controlled by the combustor; (5) digital GIS and date stamp-imbedded photo of the combustor once it is installed; and (6) certification of continuous compliance. The owner or operator would be required to submit information to CEDRI in lieu of a field performance test.

[125] See *www.epa.gov/oilandgas.*

D. Electronic Reporting and Transparency

1. Include Robust Federal Reporting With Easy Access to Information

We have the opportunity to expand transparency by making the information we have today more accessible, and making new information, obtained from advanced emissions monitoring and electronic reporting, publicly available. This approach will empower communities to play an active role in compliance oversight and improve the performance of both the government and regulated entities. On September 30, 2013, the EPA established that the default assumption for all new EPA rules is to use e-reporting, absent a compelling reason to use paper reporting.[126] Current reporting requirements in most rules and permits direct regulated entities to submit paper reports and forms to the EPA, states, and tribes. Under electronic, or e-reporting, paper reporting is replaced by standardized, Internet-based, electronic reporting to a central repository using specifically developed forms, templates and tools. E-reporting is not simply a regulated entity emailing an electronic copy of a document (*e.g.*, a PDF file) to the government, but also a means to make collected information easily accessible to the public and other stakeholders.

On March 20, 2015, the EPA proposed the ''Electronic Reporting and Recordkeeping Requirements for New Source Performance Standards'' (80 FR 15099, March 20, 2015). If adopted, the rule would revise the part 60 General Provisions and various NSPS subparts in part 60 of title 40 of the Code of Federal Regulations (CFR) to require affected facilities to submit specified air emissions data reports to the EPA electronically and to allow affected facilities to maintain electronic records of these reports. This proposed rule focuses on the submission of electronic reports to the EPA that provide direct measures of air emissions data such as summary reports, excess emission reports, performance test reports and performance evaluation reports.

Subpart OOOO is one of the rules potentially affected by this rulemaking. When promulgated, § 60.5420(c)(9) would be amended to require the submittal of reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/*).) The owner or operator would be

[126] EPA, Policy Statement on E-Reporting in EPA Regulations (September 30, 2013).

required to use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, the owner or operator would submit the report to the Administrator at the appropriate address listed in § 60.4 of the General Provisions. The owner or operator must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The EPA is currently working to develop the form for subpart OOOO.

2. Potential To Enhance Public Transparency Through Web Site Posting on Company Maintained Web Site

The public disclosure of compliance information by regulated entities to customers, ratepayers, or stakeholders has been shown to reduce pollution and improve compliance. This disclosure will empower communities and other stakeholders to play an active role in compliance oversight and improve the performance of both the government and regulated entities. A study of the Safe Drinking Water Act's (SDWA) Consumer Confidence Reports (CCR) requirements linked direct disclosures of compliance information to drinking water customers to statistically significant compliance improvements and reduced pollution.[127] Additional studies have linked public information disclosure to pollution reductions,[128] improved water pollution control practices,[129] reduced air emissions and improved environmental regulatory compliance,[130] and health and safety improvements in the automobile and restaurant markets.

A 2014 study specific to the oil and natural gas industry [131] relied solely on publicly available information that companies provide on their Web sites, or in publicly released financial statements or other reports linked from their Web sites. The report focused on promoting improved operational practices among oil and natural gas companies engaged in horizontal drilling and hydraulic fracturing. According to the report, ''[f]ollowing the maxim of what gets measured, gets managed,'' this report encourages oil and natural gas companies to increase disclosures about their use of current best practices to minimize the environmental risks and community impacts of their ''fracking'' activities. A key finding of the report was that across the industry, ''companies are failing to provide investors and other key stakeholders with quantitative, play-by-play disclosure of operational impacts and best management practices'' (while noting an increase in any level of reporting over 2013).

The EPA solicits comment on requiring owners and operators of affected facilities to report quantitative environmental results on their corporate maintained Web sites. Such results might include monitoring data (including fugitives), quantification of excess emissions and corrective actions, results of performance tests, affected facility status with respect to a standard contained in a rule, and third-party certifications. The EPA requests comment on whether all owner and operators should be required to do this, or only a subset (e.g., based on size of entity, complexity or number of operations, web presence, etc.) and what data we should require them to report; keeping in mind that monitoring and reporting requirements that may be sufficient for government regulators may be insufficient for the public. Government regulators may be satisfied with a regulation that requires a facility to monitor specified parameters (e.g., operating temperature) to generally assure that the facility is operating properly, and to perform a formal compliance test (e.g., measuring actual smokestack emissions) only upon the government's request.

3. Potential to Promote Advances in Data Capture (*e.g.,* ''Check-In App'' With Location and Photos)

One of the advances of the digital age is the ability to ''check-in'' with geospatial accuracy at any location. For example, in the 2012 NSPS, we provided a mechanism by which owners and operators could streamline annual reporting of well completions by using a digital camera to document that a well completion was performed in compliance with the NSPS. In lieu of submitting voluminous hard copies of well completion records in their annual report, the owner or operator could document the completions with a digital photograph of the REC equipment in use, with the date and geospatial coordinates shown on the photographs. These photographs would be submitted digitally or in hard copy form with the next annual report, along with a list of well completions performed with identifying information for each well completed. This option has been referred to as ''REC PIX.'' Building on the success of REC PIX, the EPA would like to explore this opportunity as it relates to advances in data capture to ensure that other compliant practices are in effect. For example, pictures of storage vessels could provide visual evidence of staining related to excess emissions events. As discussed previously, digital pictures and frame captures can help ensure that optical gas imaging for fugitive emissions is being performed properly. The EPA requests

[127] Lori S. Bennear and Sheila M. Olmstead, *Impacts of the ''Right to Know'': Information Disclosure and the Violation of Drinking Water Standards,* 56 J. ENVT'L ECON. & MGMT. 117 (2008) (finding that when larger utilities were required to mail annual Consumer Confidence Reports on water-supplier compliance pursuant to the 1998 Safe Drinking Water Act amendments, those utilities' total violations were reduced by 30–44% and more severe health violations by 40–57%).

[128] Using a micro-level data set linking Toxic Release Inventory (TRI) releases to plant-level Census data, one researcher found, among other things, that state and local government use of TRI disclosures helped induce firms to become cleaner. Linda T.M. Bui, *Public Disclosure of Private Information as a Tool for Regulating Environmental Emissions: Firm-Level Responses by Petroleum Refineries to the Toxics Release Inventory* (Brandeis Univ. Working Paper Series, Working Paper No. 05–13, 2005), available at *ftp://ftp2.census.gov/ces/wp/2005/CES-WP-05-13.pdf.* See also, Shameek Komar & Mark A. Cohen, *Information As Regulation: The Effect of Community Right to Know Laws on Toxic Emissions,* 32 J. ENVT'L ECON. & MGMT. 109 (1997), available at *http://www.sciencedirect.com/science/article/pii/S0095069696909559* (finding that the top 40 firms with the largest drop in stock price following their disclosure of TRI emissions subsequently reduced their average emissions more than other firms in their industry, including the top 40 firms with the largest TRI emissions per thousand dollars in revenue [TRI/$]; these firms both significantly reduced their average emissions and made significant attempts to improve their environmental performance by reducing the frequency and severity of chemical and oil spills).

[129] DAVID WHEELER, WORLD BANK REPORT NO. 16513–BR, INFORMATION IN POLLUTION MANAGEMENT: THE NEW MODEL 14 (1997), available at *http://web.worldbank.org/archive/website01004/WEB/IMAGES/BRAZILIN.PDF* (finding that Indonesia's Program for Pollution Control, Evaluation and Rating improved the studied facilities' ratings pursuant to a color-coded scheme).

[130] In 1990, the Ministry of Environment, Lands and Parks of British Columbia, Canada (MOE) employed a public disclosure strategy releasing a list of industrial operations that were not in compliance with their waste management permits or were deemed to be a potential pollution concern. Simultaneously, the Government of British Columbia introduced revised regulations to its pulp and paper regulations setting stricter standards and also increasing the maximum amount of fines under the Waste Management Act. Results indicated that the public disclosure strategy had a larger impact on both emissions levels and compliance status than traditional enforcement strategies, including fines, orders, and penalties. The results also indicated that the adoption of stricter standards and higher penalties also had a significant impact on decreasing emissions levels. Jérôme Foulon et al., *Incentives for Pollution Control: Regulation and Public Disclosure* 5 (World Bank Pol'y Res., Working Paper No. 2291, 2000), available at *http://papers.ssrn.com/sol3/papers.cfm?abstract_id=629138.*

[131] Richard Liroff, D. F. (2014). *Disclosing the Facts: Transparency and Risk in Hydraulic Fracturing.*

comments on viability and benefits of this approach, and to which areas it might be expanded.

XI. Impacts of This Proposed Rule

A. What are the air impacts?

For this action, the EPA estimated the emission reductions that will occur due to the implementation of the proposed emission limits. The EPA estimated emission reductions based on the control technologies proposed as the BSER. This analysis estimates regulatory impacts for the analysis years of 2020 and 2025. The analysis of 2020 is assumed to represent the first year the full suite of proposed standards is in effect and thus represents a single year of potential impacts. We estimate impacts in 2025 to illustrate how new and modified sources accumulate over time under the proposed NSPS. The regulatory impact estimates for 2025 include sources newly affected in 2025 as well as the accumulation of affected sources from 2020 to 2024 that are also assumed to be in continued operation in 2025, thus incurring compliance costs and emissions reductions in 2025.

While the EPA is proposing an exclusion from fugitive emission requirements for low production well sites, there is uncertainty in how many well sites this exclusion might affect in the future. As a result, the analysis in this RIA presents a ''low'' impact case and ''high'' impact case for fugitive emissions requirements at well sites. The low impact case excludes from analysis an estimate of low production sites, based on the first month of production data from wells newly completed or modified in 2012. The high impact case includes these well sites. National-level results for the proposed NSPS, then, are presented as ranges.

In 2020, we have estimated that the proposed NSPS would reduce about 170,000 to 180,000 tons of methane emissions and 120,000 tons of VOC emissions from affected facilities. In 2025, we have estimated that the proposed NSPS would reduce about 340,000 to 400,000 tons of methane emissions and 170,000 to 180,000 tons of VOC emissions from affected facilities. The NSPS is also expected to concurrently reduce about 310 to 400 tons HAP in 2020 and 1,900 to 2,500 tons HAP in 2025.

As described in the TSD and RIA for this proposal, the EPA projected affected facilities using a combination of historical data from the U.S. GHG Inventory, and projected activity levels, taken from the Energy Information Administration (EIA's) Annual Energy Outlook (AEO). The EPA also considered state regulations with similar requirements to the proposed NSPS in projecting affected sources for impacts analyses supporting this proposed rule. The EPA solicits comments on these projection methods as well as solicits information that would improve our estimate of the turnover rates and rates of modification of relevant sources and the number of wells on multi-well well sites.

B. What are the energy impacts?

Energy impacts in this section are those energy requirements associated with the operation of emission control devices. Potential impacts on the national energy economy from the rule are discussed in the economic impacts section. There would be little national energy demand increase from the operation of any of the environmental controls proposed in this action.

The proposed NSPS encourages the use of emission controls that recover hydrocarbon products, such as methane that can be used on-site as fuel or reprocessed within the production process for sale. We estimated that the proposed standards will result in a total cost of about $150 to $170 million in 2020 and $320 to $420 million in 2025 (in 2012 dollars).

C. What are the compliance costs?

The EPA estimates the total capital cost of the proposed NSPS will be $170 to $180 million in 2020 and $280 to $330 million in 2025. The estimate of total annualized engineering costs of the proposed NSPS is $180 to $200 million in 2020 and $370 to $500 million in 2025. This annual cost estimate includes the cost of capital, operating and maintenance costs, and monitoring, reporting, and recordkeeping costs. This estimated annual cost does not take into account any producer revenues associated with the recovery of salable natural gas. The EPA estimates that about 8 million Mcf in 2020 and 16 to 19 million Mcf of natural gas in 2025 will be recovered by implementing the proposed NSPS. In the engineering cost analysis, we assume that producers are paid $4 per thousand cubic feet (Mcf) for the recovered gas at the wellhead. After accounting for these revenues, the estimate of total annualized engineering costs of the proposed NSPS are estimated to be $150 to $170 million in 2020 and $320 to $420 million in 2025. The price assumption is influential on estimated annualized engineering costs. A simple sensitivity analysis indicates $1/Mcf change in the wellhead price causes a change in estimated engineering compliance costs of about $8 million in 2020 and $16 to $19 million in 2025.

D. What are the economic and employment impacts?

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

The NEMS-based analysis estimates natural gas and crude oil production levels remain essentially unchanged under the proposed rule in 2020, while slight declines are estimated for 2025 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020 under the proposed rule, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Executive Order 13563 directs federal agencies to consider the effect of regulations on job creation and employment. According to the Executive Order, ''our regulatory system must protect public health, welfare, safety, and our environment while promoting economic growth, innovation, competitiveness, and job creation. It must be based on the best available science.'' (Executive Order 13563, 2011) Although standard benefit-cost analyses have not typically included a separate analysis of regulation-induced employment impacts, we typically conduct employment analyses. During the current economic recovery, employment impacts are of particular concern and questions may arise about their existence and magnitude.

EPA estimated the labor impacts due to the installation, operation, and maintenance of control equipment, control activities, and labor associated with new reporting and recordkeeping requirements. We estimated up-front and continual, annual labor requirements by estimating hours of labor required for compliance and converting this number to full-time equivalents (FTEs) by dividing by 2,080 (40 hours per week multiplied by 52 weeks). The up-front labor requirement to comply with the proposed NSPS is estimated at about 50 to 70 FTEs in 2020 and 50 to 70 FTEs in 2025. The annual labor requirement to comply with proposed NSPS is estimated at about 470 to 530 FTEs in 2020 and 1,100 to 1,400 FTEs in 2025.

We note that this type of FTE estimate cannot be used to identify the specific number of people involved or whether new jobs are created for new employees, versus displacing jobs from other sectors of the economy.

E. What are the benefits of the proposed standards?

The proposed rule is expected to result in significant reductions in emissions. In 2020, the proposed rule is anticipated to reduce 170,000 to 180,000 tons of methane (a GHG and a precursor to global ozone formation), 120,000 tons of VOC (a precursor to both PM (2.5 microns and less) ($PM_{2.5}$) and ozone formation), and 310 to 400 tons of HAP. In 2025, the proposed rule is anticipated to reduce 340,000 to 400,000 tons of methane, 170,000 to 180,000 tons of VOC, and 1,900 to 2,500 tons of HAP. These pollutants are associated with substantial health effects, climate effects, and other welfare effects.

The proposed standards are expected to reduce methane emissions annually by about 3.8 to 4.0 million metric tons CO_2 Eq. in 2020 and by about 7.7 to 9.0 million metric tons CO_2 Eq. in 2025. The methane reductions represent about 2 percent in 2020 and 4 to 5 percent in 2025 of the baseline methane emissions for this sector reported in the U.S. GHG Inventory for 2013 (about 182 million metric tons CO_2 Eq. when petroleum refineries and petroleum transportation are excluded because these sources are not examined in this proposal). However, it is important to note that the emission reductions are based upon predicted activities in 2020 and 2025; the EPA did not forecast sector-level emissions in 2020 and 2025 for this rulemaking.

Methane is a potent GHG that, once emitted into the atmosphere, absorbs terrestrial infrared radiation that contributes to increased global warming and continuing climate change. Methane reacts in the atmosphere to form tropospheric ozone and stratospheric water vapor, both of which also contribute to global warming. When accounting for the impacts changing methane, tropospheric ozone, and stratospheric water vapor concentrations, the Intergovernmental Panel on Climate Change (IPCC) 5th Assessment Report (2013) found that historical emissions of methane accounted for about 30 percent of the total current warming influence (radiative forcing) due to historical emissions of GHGs. Methane is therefore a major contributor to the climate change impacts described previously. In 2013, total methane emissions from the oil and natural gas industry represented nearly 29 percent of the total methane emissions from all sources and account for about 3 percent of all CO_2-equivalent emissions in the United States, with the combined petroleum and natural gas systems being the largest contributor to U.S. anthropogenic methane emissions.

We calculated the global social benefits of methane emission reductions expected from the proposed NSPS standards for oil and natural gas sites using estimates of the social cost of methane (SC-CH_4), a metric that estimates the monetary value of impacts associated with marginal changes in methane emissions in a given year. The SC-CH_4 estimates applied in this analysis were developed by Marten et al. (2014) and are discussed in greater detail below.

A similar metric, the social cost of CO_2 (SC-CO_2), provides important context for understanding the Marten et al. SC-CH_4 estimates.[132] The SC-CO_2 is a metric that estimates the monetary value of impacts associated with marginal changes in CO_2 emissions in a given year. Similar to the SC-CH_4, it includes a wide range of anticipated climate impacts, such as net changes in agricultural productivity, property damage from increased flood risk, and changes in energy system costs, such as reduced costs for heating and increased costs for air conditioning. Estimates of the SC-CO_2 have been used by the EPA and other federal agencies to value the impacts of CO_2 emissions changes in benefit cost analysis for GHG-related rulemakings since 2008.

The SC-CO_2 estimates were developed over many years, using the best science available, and with input from the public. Specifically, an interagency working group (IWG) that included EPA and other executive branch agencies and offices used three integrated assessment models (IAMs) to develop the SC-CO_2 estimates and recommended four global values for use in regulatory analyses. The SC-CO_2 estimates were first released in February 2010 and updated in 2013 using new versions of each IAM. The 2010 SC-CO_2 Technical Support Document (2010 TSD) provides a complete discussion of the methods used to develop these estimates and the current SC-CO_2 TSD presents and discusses the 2013 update (including recent minor technical corrections to the estimates).[133]

The SC-CO_2 TSDs discuss a number of limitations to the SC-CO_2 analysis, including the incomplete way in which the IAMs capture catastrophic and non-catastrophic impacts, their incomplete treatment of adaptation and technological change, uncertainty in the extrapolation of damages to high temperatures, and assumptions regarding risk aversion. Currently, IAMs do not assign value to all of the important physical, ecological, and economic impacts of climate change recognized in the climate change literature due to a lack of precise information on the nature of damages and because the science incorporated into these models understandably lags behind the most recent research. Nonetheless, these estimates and the discussion of their limitations represent the best available information about the social benefits of CO_2 reductions to inform benefit-cost analysis. EPA and other agencies continue to engage in research on modeling and valuation of climate impacts with the goal to improve these estimates, and continue to consider feedback on the SC-CO_2 estimates from stakeholders through a range of channels, including public comments on Agency rulemakings a separate recent OMB public comment solicitation, and through regular interactions with stakeholders and research analysts implementing the SC-CO_2 methodology. See the RIA of this rule for additional details.

A challenge particularly relevant to this proposal is that the IWG did not estimate the social costs of non-CO_2 GHG emissions at the time the SC-CO_2

[132] Previous analyses have commonly referred to the social cost of carbon dioxide emissions as the social cost of carbon or SCC. To more easily facilitate the inclusion of non-CO_2 GHGs in the discussion and analysis the more specific SC-CO_2 nomenclature is used to refer to the social cost of CO_2 emissions.

[133] Both the 2010 SC-CO_2 TSD and the current TSD are available at: *https://www.whitehouse.gov/omb/oira/social-cost-of-carbon*.

estimates were developed. In addition, the directly modeled estimates of the social costs of non-CO_2 GHG emissions previously found in the published literature were few in number and varied considerably in terms of the models and input assumptions they employed[134] (EPA 2012). As a result, benefit-cost analyses informing U.S. federal rulemakings to date have not fully considered the monetized benefits associated with CH_4 emissions mitigation. To understand the potential importance of monetizing non-CO_2 GHG emissions changes, EPA has conducted sensitivity analysis in some of its past regulatory analyses using an estimate of the GWP of CH_4 to convert emission impacts to CO_2 equivalents, which can then be valued using the SC-CO_2 estimates. This approach approximates the social cost of methane (SC-CH_4) using estimates of the SC-CO_2 and the GWP of CH_4.[135]

The published literature documents a variety of reasons that directly modeled estimates of SC-CH_4 are an analytical improvement over the estimates from the GWP approximation approach. Specifically, several recent studies found that GWP-weighted benefit estimates for methane are likely to be lower than the estimates derived using directly modeled social cost estimates for these gases.[136] The GWP reflects only the relative integrated radiative forcing of a gas over 100 years in comparison to CO_2. The directly modeled social cost estimates differ from the GWP-scaled SC-CO_2 because the relative differences in timing and magnitude of the warming between gases are explicitly modeled, the non-linear effects of temperature change on economic damages are included, and rather than treating all impacts over a hundred years equally, the modeled damages over the time horizon considered (2300 in this case) are discounted to present value terms. A detailed discussion of the limitations of the GWP approach can be found in the RIA.

In general, the commenters on previous rulemakings strongly encouraged the EPA to incorporate the monetized value of non-CO_2 GHG impacts into the benefit cost analysis. However they noted the challenges associated with the GWP approach, as discussed above, and encouraged the use of directly modeled estimates of the SC-CH_4 to overcome those challenges.

Since then, a paper by Marten et al. (2014) has provided the first set of published SC-CH_4 estimates in the peer-reviewed literature that are consistent with the modeling assumptions underlying the SC-CO_2 estimates.[137] [138] Specifically, the estimation approach of Marten et al. used the same set of three IAMs, five socioeconomic and emissions scenarios, equilibrium climate sensitivity distribution, three constant discount rates, and aggregation approach used by the IWG to develop the SC-CO_2 estimates.

The SC-CH_4 estimates from Marten et al. (2014) are presented below in Table 6. More detailed discussion of the SC-CH_4 estimation methodology, results and a comparison to other published estimates can be found in the RIA and in Marten et al.

TABLE 6—SOCIAL COST OF CH_4, 2012–2050 [a]

[In 2012$ per metric ton] (Source: Marten et al., 2014 [b])

Year	SC-CH_4			
	5% Average	3% Average	2.5% Average	3% 95th Percentile
2012	$430	$1000	$1400	$2800
2015	490	1100	1500	3000
2020	580	1300	1700	3500
2025	700	1500	1900	4000
2030	820	1700	2200	4500
2035	970	1900	2500	5300
2040	1100	2200	2800	5900
2045	1300	2500	3000	6600
2050	1400	2700	3300	7200

Notes:

[a] There are four different estimates of the SC-CH_4, each one emissions-year specific. The first three shown in the table are based on the average SC-CH_4 from three integrated assessment models at discount rates of 5, 3, and 2.5 percent. The fourth estimate is the 95th percentile of the SC-CH_4 across all three models at a 3 percent discount rate. See RIA for details.

[b] The estimates in this table have been adjusted to reflect the minor technical corrections to the SC-CO_2 estimates described above. See the Corrigendum to Marten et al. (2014), *http://www.tandfonline.com/doi/abs/10.1080/14693062.2015.1070550*.

The application of these directly modeled SC-CH_4 estimates from Marten et al. (2014) in a benefit-cost analysis of a regulatory action is analogous to the use of the SC-CO_2 estimates. In addition, the limitations for the SC-CO_2 estimates discussed above likewise apply to the SC-CH_4 estimates, given the consistency in the methodology.

The EPA recently conducted a peer review of the application of the Marten et al. (2014) non-CO_2 social cost estimates in regulatory analysis and received responses that supported this application. See the RIA for a detailed discussion.

In light of the favorable peer review and past comments urging the EPA to

[134] U.S. EPA. 2012. Regulatory Impact Analysis Final New Source Performance Standards and Amendments to the National Emissions Standards for Hazardous Air Pollutants for the Oil and Natural Gas Industry. Office of Air Quality Planning and Standards, Health and Environmental Impacts Division. April. *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf*. Accessed March 30, 2015.

[135] For example, see (1) U.S. EPA. (2012). ''Regulatory impact analysis supporting the 2012 U.S. Environmental Protection Agency final new source performance standards and amendments to the national emission standards for hazardous air pollutants for the oil and natural gas industry.'' Retrieved from *http://www.epa.gov/ttn/ecas/regdata/RIAs/oil_natural_gas_final_neshap_nsps_ria.pdf* and (2) U.S. EPA. (2012). ''Regulatory impact analysis: Final rulemaking for 2017-2025 light-duty vehicle greenhouse gas emission standards and corporate average fuel economy standards.'' Retrieved from *http://www.epa.gov/otaq/climate/documents/420r12016.pdf*.

[136] See Waldhoff et al. (2011); Marten and Newbold (2012); and Marten et al. (2014).

[137] Marten et al. (2014) also provided the first set of SC-N_2O estimates that are consistent with the assumptions underlying the IWG SC-CO_2 estimates.

[138] Marten, A.L., E.A. Kopits, C.W. Griffiths, S.C. Newbold & A. Wolverton (2014, online publication; 2015, print publication). Incremental CH_4 and N_2O mitigation benefits consistent with the U.S. Government's SC-CO_2 estimates, Climate Policy, DOI: 10.1080/14693062.2014.912981.

value non-CO_2 GHG impacts in its rulemakings, the Agency has used the Marten et al. (2014) SC-CH_4 estimates to value methane impacts expected from this proposed rulemaking and has included those benefits in the main benefits analysis. The EPA seeks comments on the use of these directly modeled estimates, from the peer-reviewed literature, for the social cost of non-CO_2 GHGs in today's rulemaking.

The methane benefits calculated using Marten et al. (2014) are presented for years 2020 and 2025. Applying this approach to the methane reductions estimated for the NSPS proposal, the 2020 methane benefits vary by discount rate and range from about $88 million to approximately $550 million; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $200 to $210 million in 2020. The methane benefits increase in the 2025, ranging from $220 million to $1.4 billion, depending on discount rate used; the mean SC-CH_4 at the 3-percent discount rate results in an estimate of about $460 to $550 million in 2025.

TABLE 7—ESTIMATED GLOBAL BENEFITS OF METHANE REDUCTIONS

[In millions, 2012$]

Discount rate and statistic	Year	
	2020	2025
Million metric tonnes of methane reduced	0.15 to 0.16	0.31 to 0.36.
Million metric tonnes of CO_2 Eq.	3.8 to 4.0	7.7 to 9.0.
5% (average)	$88 to $93	$220 to $250.
3% (average)	$200 to $210	$460 to $550.
2.5% (average)	$260 to $280	$600 to $700.
3% (95th percentile)	$520 to $550	$1,200 to $1,400.

In addition to the limitation discussed above, and the referenced documents, there are additional impacts of individual GHGs that are not currently captured in the IAMs used in the directly modeled approach of Marten et al. (2014), and therefore not quantified for the rule. For example, in addition to being a GHG, methane is a precursor to ozone. The ozone generated by methane has important non-climate impacts on agriculture, ecosystems, and human health. The RIA describes the specific impacts of methane as an ozone precursor in more detail and discusses studies that have estimated monetized benefits of these methane generated ozone effects. The EPA continues to monitor developments in this area of research and seeks comment on the potential inclusion of health impacts of ozone generated by methane in future regulatory analysis.

With the data available, we are not able to provide credible health benefit estimates for the reduction in exposure to HAP, ozone and $PM_{2.5}$ for these rules, due to the differences in the locations of oil and natural gas emission points relative to existing information and the highly localized nature of air quality responses associated with HAP and VOC reductions. This is not to imply that there are no benefits of the rules; rather, it is a reflection of the difficulties in modeling the direct and indirect impacts of the reductions in emissions for this industrial sector with the data currently available.[139] In addition to health improvements, there will be improvements in visibility effects, ecosystem effects and climate effects, as well as additional product recovery.

Although we do not have sufficient information or modeling available to provide quantitative estimates for this rulemaking, we include a qualitative assessment of the health effects associated with exposure to HAP, ozone and $PM_{2.5}$ in the RIA for this rule. These qualitative effects are briefly summarized below, but for more detailed information, please refer to the RIA, which is available in the docket. One of the HAPs of concern from the oil and natural gas sector is benzene, which is a known human carcinogen. VOC emissions are precursors to both $PM_{2.5}$ and ozone formation. As documented in previous analyses (U.S. EPA, 2006,[140] U.S. EPA, 2010,[141] and U.S. EPA, 2014[142]), exposure to $PM_{2.5}$ and ozone is associated with significant public health effects. $PM_{2.5}$ is associated with health effects, including premature mortality for adults and infants, cardiovascular morbidity such as heart attacks, and respiratory morbidity such as asthma attacks, acute bronchitis, hospital admissions and emergency room visits, work loss days, restricted activity days and respiratory symptoms, as well as visibility impairment.[143] Ozone is associated with health effects, including hospital and emergency department visits, school loss days and premature mortality, as well as injury to vegetation and climate effects.[144]

Finally, the control techniques to meet the standards are anticipated to have minor secondary emissions impacts, which may partially offset the direct benefits of this rule. The magnitude of these secondary air pollutant impacts is small relative to the

[139] Previous studies have estimated the monetized benefits-per-ton of reducing VOC emissions associated with the effect that those emissions have on ambient $PM_{2.5}$ levels and the health effects associated with $PM_{2.5}$ exposure (Fann, Fulcher, and Hubbell, 2009). While these ranges of benefit-per-ton estimates can provide useful context, the geographic distribution of VOC emissions from the oil and gas sector are not consistent with emissions modeled in Fann, Fulcher, and Hubbell (2009). In addition, the benefit-per-ton estimates for VOC emission reductions in that study are derived from total VOC emissions across all sectors. Coupled with the larger uncertainties about the relationship between VOC emissions and $PM_{2.5}$ and the highly localized nature of air quality responses associated with HAP and VOC reductions, these factors lead us to conclude that the available VOC benefit-per-ton estimates are not appropriate to calculate monetized benefits of these rules, even as a bounding exercise.

[140] U.S. EPA. *RIA. National Ambient Air Quality Standards for Particulate Matter,* Chapter 5. Office of Air Quality Planning and Standards, Research Triangle Park, NC. October 2006. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/Chapter%205-Benefits.pdf.*

[141] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. January 2010. Available on the Internet at *http://www.epa.gov/ttn/ecas/regdata/RIAs/s1-supplemental_analysis_full.pdf.*

[142] U.S. EPA. *RIA. National Ambient Air Quality Standards for Ozone.* Office of Air Quality Planning and Standards, Research Triangle Park, NC. December 2014. Available on the Internet at *http://www.epa.gov/ttnecas1/regdata/RIAs/20141125ria.pdf.*

[143] U.S. EPA. *Integrated Science Assessment for Particulate Matter (Final Report).* EPA–600–R–08–139F. National Center for Environmental Assessment—RTP Division. December 2009. Available at *http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=216546.*

[144] U.S. EPA. *Air Quality Criteria for Ozone and Related Photochemical Oxidants (Final).* EPA/600/R–05/004aF–cF. Washington, DC: U.S. EPA. February 2006. Available on the Internet at *http://cfpub.epa.gov/ncea/CFM/recordisplay.cfm?deid=149923.*

direct emission reductions anticipated from this rule.

In particular, EPA has estimated that an increase in flaring of methane in response to this rule will produce a variety of emissions, including 610,000 tons of CO_2 in 2020 and 750,000 tons of CO_2 in 2025. EPA has not estimated the monetized value of the secondary emissions of CO_2 because much of the methane that would have been released in the absence of the flare would have eventually oxidized into CO_2 in the atmosphere. Note that the CO_2 produced from the methane oxidizing in the atmosphere is not included in the calculation of the SC-CH_4. However, EPA recognizes that because the growth rate of the SC-CO_2 estimates are lower than their associated discount rates, the estimated impact of CO_2 produced in the future from oxidized methane would be less than the estimated impact of CO_2 released immediately from flaring, which would imply a small disbenefit associated with flaring. Assuming an average methane oxidation period of 8.7 years, consistent with the lifetime used in IPCC AR4, the disbenefits associated with destroying one ton of methane and releasing the CO_2 emissions in 2020 instead of being released in the future via the methane oxidation process is estimated to be $6 to $25, depending on the SC-$CO_2$ value or 0.7 percent to 1.0 percent of the SC-CH_4 estimates for 2020. The analogous estimates for 2025 are $7 to $34 or 0.8 percent to 1.0 percent of the SC-CH_4 estimates for 2025. While EPA is not accounting for the CO_2 disbenefits at this time, we request comment on the appropriateness of the monetization of such impacts using the SC-CO_2 and aspects of the calculation. See RIA for further details about the calculation.

XII. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Order 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is an economically significant regulatory action that was submitted to the OMB for review. Any changes made in response to OMB recommendations have been documented in the docket. The EPA prepared an analysis of the potential costs and benefits associated with this action.

In addition, the EPA prepared a Regulatory Impact Analysis (RIA) of the potential costs and benefits associated with this action. 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. Table 8 shows the results of the cost and benefits analysis for these proposed rules.

TABLE 8—SUMMARY OF THE MONETIZED BENEFITS, SOCIAL COSTS AND NET BENEFITS FOR THE PROPOSED OIL AND NATURAL GAS NSPS IN 2020 AND 2025

[Millions of 2012$]

	2020	2025
Total Monetized Benefits [1]	$200 to $210 million	$460 to $550 million.
Total Costs [2]	$150 to $170 million	$320 to $420 million.
Net Benefits [3]	$35 to $42 million	$120 to $150 million.
Non-monetized Benefits	Non-monetized climate benefits. Health effects of $PM_{2.5}$ and ozone exposure from 120,000 tons of VOC in 2020 and 170,000 to 180,000 tons of VOC in 2025. Health effects of HAP exposure from 310 to 400 tons of HAP in 2020 and 1,900 to 2,500 tons of HAP in 2025. Health effects of ozone exposure from 170,000 to 180,000 tons of methane in 2020 and 340,000 to 400,000 tons methane in 2025. Visibility impairment. Vegetation effects.	

[1] We estimate methane benefits associated with four different values of a one ton CH_4 reduction (model average at 2.5 percent discount rate, 3 percent, and 5 percent; 95th percentile at 3 percent). For the purposes of this table, we show the benefits associated with the model average at 3 percent discount rate, however we emphasize the importance and value of considering the full range of social cost of methane values. We provide estimates based on additional discount rates in preamble section XI and in the RIA. Also, the specific control technologies for the proposed NSPS are anticipated to have minor secondary disbenefits. The net CO_2-equivalent (CO_2 Eq.) methane emission reductions are 3.8 to 4.0 million metric tons in 2020 and 7.7 to 9.0 million metric tons in 2025.

[2] The engineering compliance costs are annualized using a 7 percent discount rate and include estimated revenue from additional natural gas recovery as a result of the NSPS. When rounded, the cost estimates are the same for the 3 percent discount rate as they are for the 7 percent discount rate cost estimates, so rounded net benefits do not change when using a 3 percent discount rate.

[3] Figures may not sum due to rounding.

B. Paperwork Reduction Act (PRA)

The Office of Management and Budget (OMB) has previously approved the information collection activities contained in 40 CFR part 60, subpart OOOO under the PRA and has assigned OMB control number 2060–0673 and ICR number 2437.01; a summary can be found at 77 FR 49537. The information collection requirements in today's proposed rule titled, Standards of Performance for Crude Oil and Natural Gas Facilities for Construction, Modification, or Reconstruction (40 CFR part 60 subpart OOOOa) have been submitted for approval to the OMB under the PRA. The ICR document prepared by the EPA has been assigned EPA ICR Number 2523.01. You can find a copy of the ICR in the docket for this rule, and is briefly summarized below.

The information to be collected for the proposed NSPS is based on notification, performance tests, recordkeeping and reporting requirements which will be mandatory for all operators subject to the final standards. Recordkeeping and reporting requirements are specifically authorized by section 114 of the CAA (42 U.S.C. 7414). The information will be used by the delegated authority (state agency, or Regional Administrator if there is no delegated state agency) to ensure that the standards and other requirements are being achieved. Based on review of the recorded information at the site and the reported information, the delegated permitting authority can identify facilities that may not be in compliance and decide which facilities, records, or processes may need inspection. 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.

Potential respondents under subpart OOOOa are owners or operators of new, modified or reconstructed oil and natural gas affected facilities as defined under the rule. None of the facilities in the United States are owned or operated by state, local, tribal or the Federal government. All facilities are privately owned for-profit businesses. The requirements in this action result in industry recording keeping and reporting burden associated with review of the requirements for all affected entities, gathering relevant information, performing initial performance tests and repeat performance tests if necessary, writing and submitting the notifications and reports, developing systems for the purpose of processing and maintaining information, and train personnel to be able to respond to the collection of information.

The estimated average annual burden (averaged over the first 3 years after the effective date of the standards) for the recordkeeping and reporting requirements in subpart OOOOa for the 2,552 owners and operators that are subject to the rule is 92,658 labor hours, with an annual average cost of $3,163,699. The annual public reporting and recordkeeping burden for this collection of information is estimated to average 3.9 hours per response. Respondents must monitor all specified criteria at each affected facility and maintain these records for 5 years. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9.

Submit your comments on the Agency's need for this information, the accuracy of the provided burden estimates and any suggested methods for minimizing respondent burden to the EPA using the docket identified at the beginning of this rule. You may also send your ICR-related comments to OMB's Office of Information and Regulatory Affairs via email to *RIA_submissions@omb.eop.gov,* Attention: Desk Officer for the EPA. Since OMB is required to make a decision concerning the ICR between 30 and 60 days after receipt, OMB must receive comments no later than November 17, 2015. The EPA will respond to any ICR-related comments in the final rule.

C. Regulatory Flexibility Act (RFA)

The RFA generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Small entities include small businesses, small organizations, and small governmental jurisdictions.

For purposes of assessing the impacts of this rule on small entities, a small entity is defined as: (1) A small business in the oil or natural gas industry whose parent company has no more than 500 employees (or revenues of less than $7 million for firms that transport natural gas via pipeline); (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 section 603 of the RFA, the EPA prepared an initial regulatory flexibility analysis (IRFA) that examines the impact of the proposed rule on small entities along with regulatory alternatives that could minimize that impact. The complete IRFA is available for review in the docket and is summarized here.

The IRFA describes the reason why the proposed rule is being considered and describes the objectives and legal basis of the proposed rule, as well as discusses related rules affecting the oil and natural gas sector. The IRFA describes the EPA's examination of small entity effects prior to proposing a regulatory option and provides information about steps taken to minimize significant impacts on small entities while achieving the objectives of the rule.

The EPA also summarized the potential regulatory cost impacts of the proposed rule and alternatives in Section 3 of the RIA. The analysis in the IRFA drew upon the same analysis and assumptions as the analyses presented in the RIA. The IRFA analysis is presented in its entirely in Section 7.3 of the RIA.

Identifying impacts on specific entities is challenging because of the difficulty of predicting potentially affected new or modified sources at the firm level. To identify potentially affected entities under the proposed NSPS, the EPA combined information from industry databases to identify firms drilling and completing wells in 2012, as well as identified their oil and natural gas production levels for that year.

The EPA based the analysis in the IRFA on impacts estimates for the proposed requirements for hydraulically fractured and re-fractured oil well completions and well site fugitive emissions. While the IRFA does not incorporate potential impacts from other provisions of the proposed NSPS, the completions and fugitive emissions provisions represent a large majority of the estimated compliance costs of the proposed NSPS in 2020 and 2025. Note incorporating impacts from other provisions in this analysis is a limitation and underestimates impacts, but the EPA believes that detailed analysis of the two provisions impacts on small entities is illustrative of impacts on small entities from the proposed rule in its entirety.

We projected the 2012 base year estimates of incrementally affected facilities to 2020 and 2025 levels based on the same growth rates used to project future activities as described in the TSD and consistent with other analyses in the RIA. This approach assumes that no other firms perform potentially affected activities and firms performing oil and natural gas activities in 2012 will continue to do so in 2020 and 2025. While likely true for many firms, this will not be the case for all firms.

For some firms, we estimated their 2012 sales levels by multiplying 2012 oil and natural gas production levels reported in an industry database by assumed oil and natural gas prices at the wellhead. For natural gas, we assumed the $4/Mcf for natural gas. For oil prices, we estimated revenues using two alternative prices, $70/bbl and $50/bbl. In the results, we call the case using $70/bbl the "primary scenario" and the case using the $50/bbl as the "low oil price scenario".

For projected 2020 and 2025 potentially affected activities, we allocated compliance costs across entities based upon the costs estimated in the TSD and used in the RIA. The RIA and IRFA also estimates the potential implications of the proposed exclusion for low producing sites from the fugitive emission requirements. Fewer sites in the program due to this exclusion will likely lead to lower costs and emissions.

The analysis indicates about 1,200 to 2,100 small entities may be subject to the requirements for hydraulically fractured and re-fractured oil well completions and fugitive emissions requirements at well sites. The low end of this range reflects an estimate of how many entities might be excluded as a result of the low production fugitive emissions exemption. Also the cost-to-sales ratios with ratios greater than 1 percent and 3 percent increase from 2020 to 2025 as affected sources accumulate under the proposed NSPS. Cost-to-sales ratios exceeding 1 percent and 3 percent are also reduced from the case without the entities that might be excluded from fugitive emissions requirements as a result of the low production exemption.

The analysis above is subject to a number of caveats and limitations. These are discussed in detail in the IRFA, as well as in Section 3 of the RIA. As required by section 609(b) of the RFA, the EPA also convened a Small Business Advocacy Review (SBAR) Panel to obtain advice and recommendations from small entity representatives that potentially would be subject to the rule's requirements. The SBAR Panel evaluated the assembled materials and small-entity comments on issues related to elements of an IRFA. A copy of the full SBAR Panel Report is available in the rulemaking docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain any unfunded mandate as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments. The action imposes no enforceable duty on any state, local or tribal governments or the private sector.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government. These final rules primarily affect private industry and would not impose significant economic costs on state or local governments.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action has tribal implications. However, it will neither impose substantial direct compliance costs on federally recognized tribal governments, nor preempt tribal law. The majority of the units impacted by this rulemaking on tribal lands are owned by private entities, and tribes will not be directly impacted by the compliance costs associated with this rulemaking. There would only be tribal implications associated with this rulemaking in the case where a unit is owned by a tribal government or a tribal government is given delegated authority to enforce the rulemaking.

The EPA consulted with tribal officials under the ''EPA Policy on Consultation and Coordination with Indian Tribes'' early in the process of developing this regulation to permit them to have meaningful and timely input into its development. Additionally, the EPA has conducted meaningful involvement with tribal stakeholders throughout the rulemaking process. We provided an update on the methane strategy on the January 29, 2015, NTAA and EPA Air Policy call. As required by section 7(a), the EPA's Tribal Consultation Official has certified that the requirements of the Executive Order have been met in a meaningful and timely manner. A copy of the certification is included in the docket for this action.

Consistent with previous actions affecting the oil and natural gas sector, there is significant tribal interest because of the growth of the oil and natural gas production in Indian country. The EPA specifically solicits additional comment on this proposed action from tribal officials.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is an economically significant regulatory action as defined by Executive Order 12866, and the EPA believes that the environmental health or safety risk addressed by this action has a disproportionate effect on children. Accordingly, the agency has evaluated the environmental health and welfare effects of climate change on children.

GHGs including methane contribute to climate change and are emitted in significant quantities by the oil and gas sector. The EPA believes that the GHG emission reductions resulting from implementation of these final guidelines will further improve children's health.

The assessment literature cited in the EPA's 2009 Endangerment Finding concluded that certain populations and life stages, including children, the elderly, and the poor, are most vulnerable to climate-related health effects. The assessment literature since 2009 strengthens these conclusions by providing more detailed findings regarding these groups' vulnerabilities and the projected impacts they may experience.

These assessments describe how children's unique physiological and developmental factors contribute to making them particularly vulnerable to climate change. Impacts to children are expected from heat waves, air pollution, infectious and waterborne illnesses, and mental health effects resulting from extreme weather events. In addition, children are among those especially susceptible to most allergic diseases, as well as health effects associated with heat waves, storms, and floods. Additional health concerns may arise in low income households, especially those with children, if climate change reduces food availability and increases prices, leading to food insecurity within households.

More detailed information on the impacts of climate change to human health and welfare is provided in Section V of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use

Executive Order 13211 (66 FR 28355, May 22, 2001) provides that agencies will prepare and submit to the Administrator of the Office of Information and Regulatory Affairs, Office of Management and Budget, a Statement of Energy Effects for certain actions identified as ''significant energy actions.'' Section 4(b) of Executive Order 13211 defines ''significant energy actions'' as any action by an agency (normally published in the **Federal Register**) that promulgates or is expected to lead to the promulgation of a final rule or regulation, including notices of inquiry, advance notices of proposed rulemaking, and notices of proposed rulemaking: (1)(i) That is a significant regulatory action under Executive Order 12866 or any successor order, and (ii) is likely to have a significant adverse effect on the supply, distribution, or use of energy; or (2) that is designated by the Administrator of the Office of Information and Regulatory Affairs as a significant energy action.

This action is not a ''significant energy action'' as defined in Executive Order 13211 (66 FR 28355, May 22, 2001), because it is not likely to have a significant adverse effect on the supply, distribution, or use of energy. The basis for these determinations follows.

The EPA used the National Energy Modeling System (NEMS) to estimate the impacts of the proposed rule on the United States energy system. The NEMS is a publically-available model of the United States energy economy developed and maintained by the Energy Information Administration of the DOE and is used to produce the Annual Energy Outlook, a reference publication that provides detailed forecasts of the United States energy economy.

The EPA modeled the high impact case of the proposed NSPS with respect the low production exemption from the well site fugitive emissions requirements. As such the NEMS-based estimates of energy system impacts are likely high end estimates.

The NEMS-based analysis estimates natural gas and crude oil production levels remain essentially unchanged under the proposed rule in 2020, while slight declines are estimated for 2020 for both natural gas (about 4 billion cubic feet (bcf) or about 0.01 percent) and crude oil production (about 2,000 barrels per day or 0.03 percent). Wellhead natural gas prices for onshore lower 48 production are not estimated to change in 2020 under the proposed rule, but are estimated to increase about $0.007 per Mcf or 0.14 percent in 2025. Meanwhile, well crude oil prices for onshore lower 48 production are not estimated to change, despite the incidence of new compliance costs from the proposed NSPS. Meanwhile, net imports of natural gas are estimated to decline slightly in 2020 (by about 1 bcf or 0.05 percent) and in 2025 (by about 3 bcf or 0.09 percent). Crude oil imports are estimated to not change in 2020 and increase by about 1,000 barrels per day (or 0.02 percent) in 2025.

Additionally, the NSPS establishes several performance standards that give regulated entities flexibility in determining how to best comply with the regulation. In an industry that is geographically and economically heterogeneous, this flexibility is an important factor in reducing regulatory burden. For more information on the estimated energy effects of this proposed rule, please see the Regulatory Impact Analysis which is in the docket for this proposal.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

Section 12(d) of the National Technology Transfer and Advancement Act of 1995 (NTTAA), Public Law 104–113 (15 U.S.C. 272 note) directs the EPA to use voluntary consensus standards (VCS) in its regulatory activities unless to do so would be inconsistent with applicable law or otherwise impractical. VCS are technical standards (*e.g.*, materials specifications, test methods, sampling procedures, and business practices) that are developed or adopted by VCS bodies. NTTAA directs the EPA to provide Congress, through OMB, explanations when the Agency decides not to use available and applicable VCS.

The proposed rule involves technical standards. Therefore, the EPA conducted searches for the Oil and Natural Gas Sector: Emission Standards for New and Modified Sources through the Enhanced National Standards Systems Network (NSSN) Database managed by the American National Standards Institute (ANSI). Searches were conducted for EPA Methods 1, 1A, 2, 2A, 2C, 2D, 3A, 3B, 3C, 4, 6, 10, 15, 16, 16A, 21, 22, and 25A of 40 CFR part 60 Appendix A. No applicable voluntary consensus standards were identified for EPA Methods 1A, 2A, 2D, 21, and 22. All potential standards were reviewed to determine the practicality of the VCS for this rule. In this rule, the EPA is proposing to include in a final EPA rule regulatory text for 40 CFR part 60, subpart OOOOa that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is proposing to incorporate by reference ASME/ANSI PTC 19–10–1981 Part 10 (2010), ''Flue and Exhaust Gas Analyses'' to be used in lieu of EPA Methods 3B, 6, 6A, 6B, 15A and 16A manual portions only and not the instrumental portion. This standard includes manual and instructional methods of analysis for carbon dioxide, carbon monoxide, hydrogen sulfide, nitrogen oxides, oxygen, and sulfur dioxide. This standard is available from the American Society of Mechanical Engineers (ASME), Three Park Avenue, New York, NY 10016–5990.

The EPA welcomes comments on this aspect of the proposed rulemaking and, specifically, invites the public to identify potentially-applicable VCS and to explain why such standards should be used in this regulation.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low-income or indigenous populations. The EPA has determined this because the rulemaking 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 or indigenous populations. The EPA has provided meaningful participation opportunities for minority, low-income, indigenous populations and tribes during the pre-proposal period by conducting community calls and webinars. Additionally, the EPA will conduct outreach for communities after the rulemaking is finalized.

List of Subjects in 40 CFR Part 60

Administrative practice and procedure, Air pollution control, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping.

Dated: August 18, 2015.

Gina McCarthy,

Administrator.

For the reasons set out in the preamble, title 40, chapter I of the Code of Federal Regulations is proposed to be amended as follows:

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

■ 1. The authority citation for part 60 continues to read as follows:

AUTHORITY: 42 U.S.C. 4701, et seq.

Subpart A—[Amended]

■ 2. Section 60.17 is amended by revising paragraph (f)(14)

§ 60.17 Incorporations by reference.

* * * * *

(f) * * *

(14) ASME/ANSI PTC 19.10–1981, Flue and Exhaust Gas Analyses [Part 10, Instruments and Apparatus], (Issued August 31, 1981), IBR approved for §§ 60.56c(b), 60.63(f), 60.106(e), 60.104a(d), (h), (i), and (j), 60.105a(d), (f), and (g), § 60.106a(a), § 60.107a(a), (c), and (d), tables 1 and 3 to subpart EEEE, tables 2 and 4 to subpart FFFF, table 2 to subpart JJJJ, § 60.285a(f), §§ 60.4415(a), 60.2145(s) and (t), 60.2710(s) (t), and (w), 60.2730(q), 60.4900(b), 60.5220(b), tables 1 and 2 to subpart LLLL, tables 2 and 3 to subpart MMMM, §§ 60.5406(c) and 60.5413(b), § 60.5406a(c), § 60.5407a(g), §§ 60.5413a(b) and 60.5413a(d).

Subpart OOOO—Standards of Performance for Crude Oil and Natural Gas Production, Transmission and Distribution for which Construction, Modification or Reconstruction Commenced after August 23, 2011, and on or before September 18, 2015

■ 3. The heading for Subpart OOOO is revised to read as set forth above.

■ 4. Section 60.5360 is revised to read as follows:

§ 60.5360 What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities that commence construction, modification or reconstruction after August 23, 2011, and on or before September 18, 2015.

■ 5. Section 60.5365 is amended by:

■ a. Revising the introductory text; and

■ b. Revising paragraph (h)(4).

The revisions read as follows:

§ 60.5365 Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (g) of this section for which you commence construction, modification or reconstruction after August 23, 2011, and on or before September 18, 2015.

* * * * *

(h) * * *

(4) A gas well facility initially constructed after August 23, 2011, and on or before September 18, 2015 is considered an affected facility regardless of this provision.

■ 6. Section 60.5370 is amended by adding paragraph (d) to read as follows:

§ 60.5370 When must I comply with this subpart?

* * * * *

(d) You are deemed to be in compliance with this subpart if you are in compliance with all applicable provisions of subpart OOOOa of this part.

■ 7. Section 60.5411 is amended by: revising paragraphs (a)(3)(i)(A) and (c)(3)(i)(A) to read as follows:

§ 60.5411 What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing materials from storage vessels and centrifugal compressor wet seal degassing systems?

* * * * *

(a) * * *

(3) * * *

(i) * * *

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

(c)* * *

(3)* * *

(i) * * *

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

■ 8. Section 60.5412 is amended by:

■ a. Revising paragraphs (a)(1)(ii) and (d)(1) introductory text; and

■ b. Adding paragraph (d)(1)(iv).

The revisions and addition read as follows:

§ 60.5412 What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my storage vessel or centrifugal compressor affected facility?

* * * * *

(a) * * *

(1) * * *

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

* * * * *

(d) * * *

(1) Each enclosed combustion device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed to reduce the mass content of VOC emissions by 95.0 percent or greater. You must follow the requirements in paragraphs (d)(1)(i) through (iv) of this section.

* * * * *

(iv) Each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413.

(C) You must operate at a minimum temperature of 760°C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

* * * * *

■ 9. Section 60.5413 is amended by revising paragraph (e)(3) to read as follows:

§ 60.5413 What are the performance testing procedures for control devices used to demonstrate compliance at my storage vessel or centrifugal compressor affected facility?

* * * * *

(e) * * *

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

* * * * *

■ 10. Section 60.5415 is amended by revising paragraph (b)(2)(vii)(B) to read as follows:

§ 60.5415 How do I demonstrate continuous compliance with the standards for my gas well affected facility, my centrifugal compressor affected facility, my stationary reciprocating compressor affected facility, my pneumatic controller affected facility, my storage vessel affected facility, and my affected facilities at onshore natural gas processing plants?

* * * * *

(b) * * *

(2) * * *

(vii) * * *

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

* * * * *

■ 11. Section 60.5416 is amended by revising paragraph (c)(3)(i) to read as follows:

§ 60.5416 What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my storage vessel and centrifugal compressor affected facility?

* * * * *

(c) * * *

(3) * * *

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420(c)(8).

* * * * *

■ 12. Section 60.5417 is amended by adding paragraph (h)(4) to read as follows:

§ 60.5417 What are the continuous control device monitoring requirements for my storage vessel or centrifugal compressor affected facility?

* * * * *

(h) * * *

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

■ 13. Section 60.5420 is amended by:

■ a. Revising paragraph (c) introductory text; and

■ b. Adding paragraph (c)(14).

The revision and addition reads as follows:

§ 60.5420 What are my notification, reporting, and recordkeeping requirements?

* * * * *

(c) Recordkeeping requirements. You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (14) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years.

* * * * *

(14) A log of records as specified in §§ 60.5412(d)(1)(iii) and 60.5413(e)(4) for all inspection, repair and maintenance activities for each control devices failing the visible emissions test.

■ 14. Section 60.5430 is revised by:

■ a. Adding, in alphabetical order, a definition for the term ''capital expenditure;'' and

■ b. Revising the definition for ''group 2 storage vessel.''

The addition and revision read as follows:

§ 60.5430 What definitions apply to this subpart?

* * * * *

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that:

(1) Exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where

(i) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(ii) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(iii) The applicable basic annual asset guideline repair allowance, B, is 4.5.

* * * * *

Group 2 storage vessel means a storage vessel, as defined in this section, for which construction, modification or reconstruction has commenced after April 12, 2013, and on or before September 18, 2015.

* * * * *

■ 15. Amend Table 3 to Subpart OOOO by revising entries ''§ 60.15'' and ''§ 60.18'' to read as follows:

TABLE 3 TO SUBPART OOOO OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOO

General provisions citation	Subject of citation	Applies to subpart?	Explanation
*	*	*	* * * *
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to pneumatic controllers, centrifugal compressors or storage vessels.
*	*	*	* * * *
§ 60.18	General control device requirements.	Yes	
*	*	*	* * * *

■ 16. Add subpart OOOOa, consisting of sections 60.5360a through 60.5430a, to part 60 to read as follows:

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification, or Reconstruction Commenced after September 18, 2015

Sec.
60.5360a What is the purpose of this subpart?
60.5365a Am I subject to this subpart?
60.5370a When must I comply with this subpart?
60.5375a What methane and VOC standards apply to well affected facilities?
60.5380a What methane and VOC standards apply to centrifugal compressor affected facilities?
60.5385a What methane and VOC standards apply to reciprocating compressor affected facilities?
60.5390a What methane and VOC standards apply to pneumatic controller affected facilities?
60.5393a What methane and VOC standards apply to pneumatic pump affected facilities?
60.5395a What VOC standards apply to storage vessel affected facilities?
60.5397a What fugitive emissions methane and VOC standards apply to the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station?
60.5400a What equipment leak methane and VOC standards apply to affected facilities at an onshore natural gas processing plant?
60.5401a What are the exceptions to the equipment leak methane and VOC standards for affected facilities at onshore natural gas processing plants?
60.5402a What are the alternative emission limitations for equipment leaks from onshore natural gas processing plants?
60.5405a What standards apply to sweetening unit affected facilities at onshore natural gas processing plants?
60.5406a What test methods and procedures must I use for my sweetening unit affected facilities at onshore natural gas processing plants?
60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?
60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?
60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?
60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pump and storage vessels?
60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, pneumatic pump and storage vessel affected facilities?
60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor, pneumatic pump and storage vessel affected facilities?
60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station affected facilities, and affected facilities at onshore natural gas processing plants?
60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump, and storage vessel affected facilities?
60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor, pneumatic pump, and storage vessel affected facilities?
60.5420a What are my notification, reporting, and recordkeeping requirements?
60.5421a What are my additional recordkeeping requirements for my affected facility subject to methane and VOC requirements for onshore natural gas processing plants?
60.5422a What are my additional reporting requirements for my affected facility subject to methane and VOC requirements for onshore natural gas processing plants?
60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?
60.5425a What parts of the General Provisions apply to me?
60.5430a What definitions apply to this subpart?
60.5431a–60.5499a [Reserved]
Table 1 to Subpart OOOOa of Part 60—Required Minimum Initial SO_2 Emission Reduction Efficiency (Z_i)
Table 2 to Subpart OOOOa of Part 60—Required Minimum SO_2Emission Reduction Efficiency (Z_c)
Table 3 to Subpart OOOOa of Part 60—Applicability of General Provisions to Subpart OOOOa

Subpart OOOOa—Standards of Performance for Crude Oil and Natural Gas Facilities for which Construction, Modification or Reconstruction Commenced After September 18, 2015

§ 60.5360a What is the purpose of this subpart?

This subpart establishes emission standards and compliance schedules for the control of methane, volatile organic compounds (VOC) and sulfur dioxide (SO_2) emissions from affected facilities in the crude oil and natural gas source category that commence construction, modification or reconstruction after September 18, 2015. The effective date of the rule is [date 60 days after publication of final rule in the **Federal Register**].

§ 60.5365a Am I subject to this subpart?

You are subject to the applicable provisions of this subpart if you are the owner or operator of one or more of the onshore affected facilities listed in paragraphs (a) through (j) of this section for which you commence construction, modification or reconstruction after September 18, 2015.

(a) Each well affected facility, which is a single well that conducts a well completion operation following hydraulic fracturing or refracturing and has a gas-to-oil ratio of greater than 300 scf of gas per barrel of oil produced. The provisions of this paragraph do not affect the affected facility status of well sites for the purposes of § 60.5397a. The provisions of paragraphs (a)(1) through (4) of this section apply to wells that are hydraulically refractured:

(1) A well that conducts a well completion operation following hydraulic refracturing is not an affected facility, provided that the requirements of § 60.5375a(a)(1) through (4) are met. However, hydraulic refracturing of a well constitutes a modification of the well site for purposes of § 60.5397a, regardless of affected facility status of the well itself.

(2) A well completion operation following hydraulic refracturing not conducted pursuant to § 60.5375a(a)(1) through (4) is a modification to the well.

(3) Refracturing of a well does not affect the modification status of other equipment, process units, storage vessels, compressors, pneumatic pumps, or pneumatic controllers.

(4) A well initially constructed after September 18, 2015, that conducts a well completion operation following hydraulic refracturing is considered an affected facility regardless of this provision.

(b) Each centrifugal compressor affected facility, which is a single centrifugal compressor using wet seals. A centrifugal compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(c) Each reciprocating compressor affected facility, which is a single reciprocating compressor. A reciprocating compressor located at a well site, or an adjacent well site and servicing more than one well site, is not an affected facility under this subpart.

(d)(1) Each pneumatic controller affected facility not located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller operating at a natural gas bleed rate greater than 6 scfh.

(2) Each pneumatic controller affected facility located at a natural gas processing plant, which is a single continuous bleed natural gas-driven pneumatic controller.

(e) Each storage vessel affected facility, which is a single storage vessel with the potential for VOC emissions equal to or greater than 6 tpy as determined according to this section, except as provided in paragraphs (e)(1) through (4) of this section. The potential for VOC emissions must be calculated using a generally accepted model or calculation methodology, based on the maximum average daily throughput determined for a 30-day period of production prior to the applicable emission determination deadline specified in this section. The determination may take into account requirements under a legally and practically enforceable limit in an operating permit or other requirement established under a Federal, State, local or tribal authority.

(1) For each new, modified or reconstructed storage vessel receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, including wells subject to § 60.5375a(f), you must determine the potential for VOC emissions within 30 days after startup of production.

(2) A storage vessel affected facility that subsequently has its potential for VOC emissions decrease to less than 6 tpy shall remain an affected facility under this subpart.

(3) For storage vessels not subject to a legally and practically enforceable limit in an operating permit or other requirement established under Federal, state, local or tribal authority, any vapor from the storage vessel that is recovered and routed to a process through a VRU designed and operated as specified in this section is not required to be included in the determination of VOC potential to emit for purposes of determining affected facility status, provided you comply with the requirements in paragraphs (e)(3)(i) through (iv) of this section.

(i) You meet the cover requirements specified in § 60.5411a(b).

(ii) You meet the closed vent system requirements specified in § 60.5411a(c).

(iii) You maintain records that document compliance with paragraphs (e)(3)(i) and (ii) of this section.

(iv) In the event of removal of apparatus that recovers and routes vapor to a process, or operation that is inconsistent with the conditions specified in paragraphs (e)(3)(i) and (ii) of this section, you must determine the storage vessel's potential for VOC emissions according to this section within 30 days of such removal or operation.

(4) For each new, reconstructed, or modified storage vessel with startup, startup of production, or which is returned to service, affected facility status is determined as follows: If a storage vessel is reconnected to the original source of liquids or is used to replace any storage vessel affected facility, it is a storage vessel affected facility subject to the same requirements as before being removed from service, or applicable to the storage vessel affected facility being replaced, immediately upon startup, startup of production, or return to service.

(f) The group of all equipment, except compressors, within a process unit is an affected facility.

(1) Addition or replacement of equipment for the purpose of process improvement that is accomplished without a capital expenditure shall not by itself be considered a modification under this subpart.

(2) Equipment associated with a compressor station, dehydration unit, sweetening unit, underground storage vessel, field gas gathering system, or liquefied natural gas unit is covered by §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a of this subpart if it is located at an onshore natural gas processing plant. Equipment not located at the onshore natural gas processing plant site is exempt from the provisions of §§ 60.5400a, 60.5401a, 60.5402a, 60.5421a, and 60.5422a of this subpart.

(3) The equipment within a process unit of an affected facility located at onshore natural gas processing plants and described in paragraph (f) of this section are exempt from this subpart if they are subject to and controlled according to subparts VVa, GGG or GGGa of this part.

(g) Sweetening units located at onshore natural gas processing plants that process natural gas produced from either onshore or offshore wells.

(1) Each sweetening unit that processes natural gas is an affected facility; and

(2) Each sweetening unit that processes natural gas followed by a sulfur recovery unit is an affected facility.

(3) Facilities that have a design capacity less than 2 long tons per day (LT/D) of hydrogen sulfide (H_2S) in the acid gas (expressed as sulfur) are required to comply with recordkeeping and reporting requirements specified in § 60.5423a(c) but are not required to comply with §§ 60.5405a through 60.5407a and §§ 60.5410a(g) and 60.5415a(g) of this subpart.

(4) Sweetening facilities producing acid gas that is completely reinjected into oil-or-gas-bearing geologic strata or that is otherwise not released to the atmosphere are not subject to §§ 60.5405a through 60.5407a, 60.5410a(g), 60.5415a(g), and 60.5423a of this subpart.

(h)(1) For natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump.

(2) For locations other than natural gas processing plants, each pneumatic pump affected facility, which is a single natural gas-driven chemical/methanol pump or natural gas-driven diaphragm pump for which a control device is located on site.

(i) Except as provided in § 60.5365a(i)(1) through (i)(2), the collection of fugitive emissions components at a well site, as defined in § 60.5430a, is an affected facility.

(1) A well site with average combined oil and natural gas production for the wells at the site being less than 15 barrels of oil equivalent (boe) per day averaged over the first 30 days of production, is not an affected facility under this subpart.

(2) A well site that only contains one or more wellheads is not an affected facility under this subpart.

(3) For purposes of § 60.5397a, a "modification" to a well site occurs when:

(i) A new well is drilled at an existing well site;

(ii) A well at an existing well site is hydraulically fractured; or

(iii) A well at an existing well site is hydraulically refractured.

(j) The collection of fugitive emissions components at a compressor station, as defined in § 60.5430a, is an affected facility. For purposes of § 60.5397a, a "modification" to a compressor station occurs when:

(1) A new compressor is constructed at an existing compressor station; or

(2) A physical change is made to an existing compressor at a compressor station that increases the compression capacity of the compressor station.

(3) Reserved

§ 60.5370a When must I comply with this subpart?

(a) You must be in compliance with the standards of this subpart no later than [date 60 days after publication of final rule in the **Federal Register**] or upon startup, whichever is later.

(b) The provisions for exemption from compliance during periods of startup, shutdown and malfunctions provided for in 40 CFR 60.8(c) do not apply to this subpart.

(c) You are exempt from the obligation to obtain a permit under 40 CFR part 70 or 40 CFR part 71, provided you are not otherwise required by law to obtain a permit under 40 CFR 70.3(a) or 40 CFR 71.3(a). Notwithstanding the previous sentence, you must continue to comply with the provisions of this subpart.

§ 60.5375a What methane and VOC standards apply to well affected facilities?

If you are the owner or operator of a well affected facility, you must reduce methane and VOC emissions by complying with paragraphs (a) through (f) of this section.

(a) Except as provided in paragraph (f) of this section, for each well completion operation with hydraulic fracturing you must comply with the requirements in paragraphs (a)(1) through (4) of this section. You must maintain a log as specified in paragraph (b) of this section.

(1) For each stage of the well completion operation, as defined in § 60.5430a, follow the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) During the initial flowback stage, route the flowback into one or more well completion vessels or storage vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the initial flowback stage is not subject to control under this section.

(ii) During the separation flowback stage, route all recovered liquids from the separator to one or more well completion vessels or storage vessels, re-inject the recovered liquids into the well or another well or route the recovered liquids to a collection system. Route the recovered gas from the separator into a gas flow line or collection system, re-inject the recovered gas into the well or another well, use the recovered gas as an on-site fuel source, or use the recovered gas for another useful purpose that a purchased fuel or raw material would serve. If it is technically infeasible to route the recovered gas as required above, follow the requirements in paragraph (a)(3) of this section. If, at any time during the separation flowback stage, it is not technically feasible for a separator to function, you must comply with (a)(1)(i) of this section.

(2) All salable quality recovered gas must be routed to the gas flow line as soon as practicable. In cases where salable quality gas cannot be directed to the flow line due to technical infeasibility, you must follow the requirements in paragraph (a)(3) of this section.

(3) You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source.

(4) You have a general duty to safely maximize resource recovery and minimize releases to the atmosphere during flowback and subsequent recovery.

(b) You must maintain a log for each well completion operation at each well affected facility. The log must be completed on a daily basis for the duration of the well completion operation and must contain the records specified in § 60.5420a(c)(1)(iii).

(c) You must demonstrate initial compliance with the standards that apply to well affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with the standards that apply to well affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a.

(f)(1) For each well affected facility specified in paragraphs (f)(1)(i) and (ii) of this section, you must comply with the requirements of paragraphs (f)(2) and (3) of this section.

(i) Each well completion operation with hydraulic fracturing at a wildcat or delineation well.

(ii) Each well completion operation with hydraulic fracturing at a non-wildcat low pressure well or non-delineation low pressure well.

(2) Route the flowback into one or more well completion vessels and commence operation of a separator unless it is technically infeasible for a separator to function. Any gas present in the flowback before the separator can function is not subject to control under this section. You must capture and direct recovered gas to a completion combustion device, except in conditions that may result in a fire hazard or explosion, or where high heat emissions from a completion combustion device may negatively impact tundra, permafrost or waterways. Completion combustion devices must be equipped with a reliable continuous ignition source. You must also comply with paragraphs (a)(4) and (b) through (e) of this section.

(3) You must maintain records specified in § 60.5420a(c)(1)(iii) for wildcat, delineation and low pressure wells.

§ 60.5380a What methane and VOC standards apply to centrifugal compressor affected facilities?

You must comply with the methane and VOC standards in paragraphs (a) through (d) of this section for each centrifugal compressor affected facility.

(a)(1) You must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b). The cover must be connected through a closed vent system that meets the requirements of § 60.5411a(a) and the closed vent system must be routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(b) You must demonstrate initial compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5410a(b).

(c) You must demonstrate continuous compliance with the standards that apply to centrifugal compressor affected facilities as required by § 60.5415a(b).

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

§ 60.5385a What methane and VOC standards apply to reciprocating compressor affected facilities?

You must reduce methane and VOC emissions by complying with the standards in paragraphs (a) through (d) of this section for each reciprocating compressor affected facility.

(a) You must replace the reciprocating compressor rod packing according to either paragraph (a)(1) or (2) of this section or you must comply with paragraph (a)(3) of this section.

(1) Before the compressor has operated for 26,000 hours. The number of hours of operation must be continuously monitored beginning upon initial startup of your reciprocating compressor affected facility, or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) Prior to 36 months from the date of the most recent rod packing replacement, or 36 months from the date of startup for a new reciprocating compressor for which the rod packing has not yet been replaced.

(3) Collect the methane and VOC emissions from the rod packing using a rod packing emissions collection system which operates under negative pressure and route the rod packing emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a).

(b) You must demonstrate initial compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5410a.

(c) You must demonstrate continuous compliance with standards that apply to reciprocating compressor affected facilities as required by § 60.5415a.

(d) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a.

§ 60.5390a What methane and VOC standards apply to pneumatic controller affected facilities?

For each pneumatic controller affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (b)(1) or (c)(1) of this section, as applicable. Pneumatic controllers meeting the conditions in paragraph (a) of this section are exempt from this requirement.

(a) The requirements of paragraph (b)(1) or (c)(1) of this section are not required if you determine that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required based on functional needs, including but not limited to response time, safety and positive actuation. However, you must tag such pneumatic controller with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller, as required in § 60.5420a(c)(4)(ii).

(b)(1) Each pneumatic controller affected facility at a natural gas processing plant must have a bleed rate of zero.

(2) Each pneumatic controller affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic controller as required in § 60.5420a(c)(4)(iv).

(c)(1) Each pneumatic controller affected facility at a location other than at a natural gas processing plant must have a bleed rate less than or equal to 6 standard cubic feet per hour.

(2) Each pneumatic controller affected facility constructed, modified or reconstructed on or after October 15, 2013, at a location other than at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that controller as required in § 60.5420a(c)(4)(iii).

(d) You must demonstrate initial compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5410a.

(e) You must demonstrate continuous compliance with standards that apply to pneumatic controller affected facilities as required by § 60.5415a.

(f) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5393a What methane and VOC standards apply to pneumatic pump affected facilities?

For each pneumatic pump affected facility you must comply with the methane and VOC standards, based on natural gas as a surrogate for methane and VOC, in either paragraph (a)(1) or (b)(1) of this section, as applicable.

(a)(1) Each pneumatic pump affected facility at a natural gas processing plant must have a natural gas emission rate of zero.

(2) Each pneumatic pump affected facility at a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pneumatic pump as required in § 60.5420a(c)(16)(i).

(b)(1) Each pneumatic pump affected facility at a location other than a natural gas processing plant must reduce natural gas emissions by 95.0 percent, except as provided in paragraph (b)(2) of this section.

(2) You are not required to install a control device solely for the purposes of complying with the 95.0 percent reduction of paragraph (b)(1) of this section. If you do not have a control device installed on-site by the compliance date, then you must comply instead with the provisions of paragraphs (b)(2)(i) and (ii) of this section.

(i) Submit a certification in accordance with § 60.5420(b)(8)(i).

(ii) If you subsequently install a control device, you are no longer required to submit the certification in § 60.5420(b)(8)(i) and must be in compliance with the requirements of paragraph (b)(1) of this section within 30 days of installation of the control device. Compliance with this requirement should be reported in the next annual report in accordance with § 60.5420(b)(8)(iii).

(3) Each pneumatic pump affected facility at a location other than a natural gas processing plant must be tagged with the month and year of installation, reconstruction or modification, and identification information that allows traceability to the records for that pump as required in § 60.5420a(c)(16)(i).

(4) If you use a control device to reduce emissions, you must connect the pneumatic pump affected facility through a closed vent system that meets the requirements of § 60.5411a(a) and route emissions to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c) and performance tested in accordance with § 60.5413a. As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process.

(c) You must demonstrate initial compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5410a.

(d) You must demonstrate continuous compliance with standards that apply to pneumatic pump affected facilities as required by § 60.5415a.

(e) You must perform the required notification, recordkeeping, and reporting as required by § 60.5420a, except that you are not required to submit the notifications specified in § 60.5420a(a).

§ 60.5395a What VOC standards apply to storage vessel affected facilities?

Except as provided in paragraph (e) of this section, you must comply with the VOC standards in this section for each storage vessel affected facility.

(a) You must comply with either the requirements of paragraphs (a)(1) and (a)(2) or the requirements of paragraph (a)(3) of this section. If you choose to meet the requirements in paragraph (a)(3) of this section, you are not required to comply with the requirements of paragraph (a)(2) of this section except as provided in paragraphs (a)(3)(i) and (ii) of this section.

(1) Determine potential for VOC emissions in accordance with § 60.5365a(e).

(2) Reduce VOC emissions by 95.0 percent within 60 days after startup. For storage vessel affected facilities receiving liquids pursuant to the standards for well affected facilities in § 60.5375a, you must achieve the required emissions reductions within 60 days after startup of production as defined in § 60.5430a.

(3) Maintain the uncontrolled actual VOC emissions from the storage vessel affected facility at less than 4 tpy without considering control. Prior to using the uncontrolled actual VOC emission rate for compliance purposes, you must demonstrate that the uncontrolled actual VOC emissions have remained less than 4 tpy as determined monthly for 12 consecutive months. After such demonstration, you must determine the uncontrolled actual VOC emission rate each month. The uncontrolled actual VOC emissions must be calculated using a generally accepted model or calculation methodology, and the calculations must be based on the average throughput for the month. You must comply with paragraph (a)(2) of this section if your storage vessel affected facility meets the conditions specified in paragraphs (a)(3)(i) or (ii) of this section.

(i) If a well feeding the storage vessel affected facility undergoes fracturing or refracturing, you must comply with paragraph (a)(2) of this section as soon as liquids from the well following fracturing or refracturing are routed to the storage vessel affected facility.

(ii) If the monthly emissions determination required in this section indicates that VOC emissions from your storage vessel affected facility increase to 4 tpy or greater and the increase is not associated with fracturing or refracturing of a well feeding the storage vessel affected facility, you must comply with paragraph (a)(2) of this section within 30 days of the monthly determination.

(b) *Control requirements.* (1) Except as required in paragraph (b)(2) of this section, if you use a control device to reduce VOC emissions from your storage vessel affected facility, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c), and you must route emissions to a control device that meets the conditions specified in § 60.5412a(c) and (d). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process that reduces VOC emissions by at least 95.0 percent.

(2) If you use a floating roof to reduce emissions, you must meet the requirements of § 60.112b(a)(1) or (2) and the relevant monitoring, inspection, recordkeeping, and reporting requirements in 40 CFR part 60, subpart Kb.

(c) *Requirements for storage vessel affected facilities that are removed from service or returned to service.* If you remove a storage vessel affected facility from service, you must comply with paragraphs (c)(1) through (3) of this section. A storage vessel is not an affected facility under this subpart for the period that it is removed from service.

(1) For a storage vessel affected facility to be removed from service, you must comply with the requirements of paragraph (c)(1)(i) and (ii) of this section.

(i) You must completely empty and degas the storage vessel, such that the storage vessel no longer contains crude oil, condensate, produced water or intermediate hydrocarbon liquids. A storage vessel where liquid is left on walls, as bottom clingage or in pools due to floor irregularity is considered to be completely empty.

(ii) You must submit a notification as required in § 60.5420a(b)(6)(v) in your next annual report, identifying each storage vessel affected facility removed from service during the reporting period and the date of its removal from service.

(2) If a storage vessel identified in paragraph (c)(1)(ii) of this section is returned to service, you must determine its affected facility status as provided in § 60.5365a(e).

(3) For each storage vessel affected facility returned to service during the reporting period, you must submit a notification in your next annual report as required in § 60.5420a(b)(6)(vi), identifying each storage vessel affected facility and the date of its return to service.

(d) *Compliance, notification, recordkeeping, and reporting.* You must comply with paragraphs (d)(1) through (3) of this section.

(1) You must demonstrate initial compliance with standards as required by § 60.5410a(h) and (i).

(2) You must demonstrate continuous compliance with standards as required by § 60.5415a(e)(3).

(3) You must perform the required notification, recordkeeping and reporting as required by § 60.5420a.

(e) Exemptions. This subpart does not apply to storage vessels subject to and controlled in accordance with the requirements for storage vessels in 40 CFR part 60, subpart Kb, 40 CFR part 63, subparts G, CC, HH, or WW.

§ 60.5397a What fugitive emissions methane and VOC standards apply to the affected facility which is the collection of fugitive emissions components at a well site and the affected facility which is the collection of fugitive emissions components at a compressor station?

For each affected facility under § 60.5365a(i) and (j), you must reduce methane and VOC emissions by complying with the requirements of paragraphs (a) through (l) of this section. These requirements are independent of the closed vent system and cover requirements in § 60.5411a.

(a) You must monitor all fugitive emission components, as defined in 60.5430a, in accordance with paragraphs (b) through (i) of this section. You must repair all sources of fugitive emissions in accordance with paragraph (j) of this section. You must keep records in accordance with paragraph (k) and report in accordance with paragraph (l) of this section. For purposes of this section, fugitive emissions are defined as: Any visible emission from a fugitive emissions component observed using optical gas imaging.

(b) You must develop a corporate-wide fugitive emissions monitoring plan that covers the collection of fugitive emissions components at well sites and compressor stations in accordance with paragraph (c) of this section, and you must develop a site-specific fugitive emissions monitoring plan specific to each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station in accordance with paragraph (d) of this section. Alternatively, you may develop a site-specific plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that covers the elements of both the corporate-wide and site-specific plans.

(c) Your corporate-wide monitoring plan must include the elements specified in paragraphs (c)(1) through (8) of this section, as a minimum.

(1) Frequency for conducting surveys. Surveys must be conducted at least as

frequently as required by paragraphs (f) through (i) of this section.

(2) Technique for determining fugitive emissions.

(3) Manufacturer and model number of fugitive emissions detection equipment to be used.

(4) Procedures and timeframes for identifying and repairing fugitive emissions components from which fugitive emissions are detected, including timeframes for fugitive emission components that are unsafe to repair. Your repair schedule must meet the requirements of paragraph (j) of this section at a minimum.

(5) Procedures and timeframes for verifying fugitive emission component repairs.

(6) Records that will be kept and the length of time records will be kept.

(7) Your plan must also include the elements specified in paragraphs (c)(7)(i) through (vii) of this section.

(i) Verification that your optical gas imaging equipment meets the specifications of paragraphs (c)(7)(i)(A) and (B) of this section. This verification is an initial verification and may either be performed by the facility, by the manufacturer, or by a third-party. For the purposes of complying with the fugitives emissions monitoring program with optical gas imaging, a fugitive emission is defined as any visible emissions observed using optical gas imaging.

(A) Your optical gas imaging equipment must be capable of imaging gases in the spectral range for the compound of highest concentration in the potential fugitive emissions.

(B) Your optical gas imaging equipment must be capable of imaging a gas that is half methane, half propane at a concentration of ≤10,000 ppm at a flow rate of ≥60 g/hr from a quarter inch diameter orifice.

(ii) Procedure for a daily verification check.

(iii) Procedure for determining the operator's maximum viewing distance from the equipment and how the operator will ensure that this distance is maintained.

(iv) Procedure for determining maximum wind speed during which monitoring can be performed and how the operator will ensure monitoring occurs only at wind speeds below this threshold.

(v) Procedures for conducting surveys, including the items specified in paragraphs (c)(7)(v)(A) through (C) of this section.

(A) How the operator will ensure an adequate thermal background is present in order to view potential fugitive emissions.

(B) How the operator will deal with adverse monitoring conditions, such as wind.

(C) How the operator will deal with interferences (*e.g.,* steam).

(vi) Training and experience needed prior to performing surveys.

(vii) Procedures for calibration and maintenance. Procedures must comply with those recommended by the manufacturer.

(d) Your site-specific monitoring plan must include the elements specified in paragraphs (d)(1) through (3) of this section, as a minimum.

(1) Deviations from your master plan.

(2) Sitemap.

(3) Your plan must also include your defined walking path. The walking path must ensure that all fugitive emissions components are within sight of the path and must account for interferences.

(e) Each monitoring survey shall observe each fugitive emissions component for fugitive emissions.

(f)(1) You must conduct an initial monitoring survey within 30 days of the first well completion for each collection of fugitive emissions components at a new well site or upon the date the well site begins the production phase for other wells. For a modified collection of fugitive emissions components at a well site, the initial monitoring survey must be conducted within 30 days of the well site modification.

(2) You must conduct an initial monitoring survey within 30 days of the startup of a new compressor station for each new collection of fugitive emissions components at the new compressor station. For modified compressor stations, the initial monitoring survey of the collection of fugitive emissions components at a modified compressor station must be conducted within 30 days of the modification.

(g) A monitoring survey of each collection of fugitive emissions components at a well site and collection of fugitive emissions components at a compressor station shall be conducted at least semiannually after the initial survey. Consecutive semiannual monitoring surveys shall be conducted at least 4 months apart.

(h) The monitoring frequency specified in paragraph (g) of this section shall be increased to quarterly in the event that two consecutive semiannual monitoring surveys detect fugitive emissions at greater than 3.0 percent of the fugitive emissions components at a well site or at greater than 3.0 percent of the fugitive emissions components at a compressor station.

(i) The monitoring frequency specified in paragraph (g) of this section may be decreased to annual in the event that two consecutive semiannual surveys detect fugitive emissions at less than 1.0 percent of the fugitive emissions components at a well site, or at less than 1.0 percent of the fugitive emissions components at a compressor station. The monitoring frequency shall return to semiannual if a survey detects fugitive emissions between 1.0 percent and 3.0 percent of the fugitive emissions components at the well site, or between 1.0 percent and 3.0 percent of the fugitive emissions components at the compressor station.

(j) For fugitive emissions components also subject to the repair provisions of §§ 60.5416a(b)(9) through (12) and (c)(4) through (7), those provisions apply instead to those closed vent system and covers, and the repair provisions of paragraphs (j)(1) and (2) of this section do not apply to those closed vent systems and covers.

(1) Each identified source of fugitive emissions shall be repaired or replaced as soon as practicable, but no later than 15 calendar days after detection of the fugitive emissions. If the repair or replacement is technically infeasible or unsafe to repair during operation of the unit, the repair or replacement must be completed during the next scheduled shutdown or within 6 months, whichever is earlier.

(2) Each repaired or replaced fugitive emissions component must be resurveyed as soon as practicable, but no later than 15 days of finding such fugitive emissions, to ensure that there is no leak.

(i) For repairs that cannot be made during the monitoring survey when the fugitive emissions are initially found, the operator may resurvey the repaired fugitive emissions components using either Method 21 or optical gas imaging within 15 days of finding such fugitive emissions.

(ii) Operators that use Method 21 to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(ii)(A) and (B).

(A) A fugitive emissions component is repaired when the Method 21 instrument indicates a concentration of less than 500 ppm above background.

(B) Operators must use the Method 21 monitoring requirements specified in paragraph § 60.5401a(g).

(iii) Operators that use optical gas imaging to resurvey the repaired fugitive emissions components, are subject to the resurvey provisions specified in paragraphs (j)(2)(iii)(A) and (B).

(A) A fugitive emissions component is repaired when the optical gas imaging instrument shows no indication of visible emissions.

(B) Operators must use the optical gas imaging monitoring requirements specified in paragraph (a).

(k) Records for each monitoring survey shall be maintained as specified § 60.5420a(c)(15) and must contain, at a minimum, the information specified in paragraphs (k)(1) through (6) of this section.

(1) Date of the survey.

(2) Beginning and end time of the survey.

(3) Name of operator(s) performing survey. You must note the training and experience of the operator.

(4) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(5) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(6) Documentation of each source of fugitive emissions (*e.g.,* fugitive emissions components), including the information specified in paragraphs (k)(6)(i) through (ii) of this section.

(i) Location.

(ii) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the well site or compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(iii) The date of successful repair of the fugitive emissions component.

(iv) The instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(l) Annual reports shall be submitted for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station that include the information specified in § 60.5420a(b)(7). Multiple collection of fugitive emissions components at a well site or collection of fugitive emissions at a compressor station may be included in a single annual report.

§ 60.5400a What equipment leak methane and VOC standards apply to affected facilities at an onshore natural gas processing plant?

This section applies to the group of all equipment, except compressors, within a process unit.

(a) You must comply with the requirements of §§ 60.482–1a(a), (b), and (d), 60.482–2a, and 60.482–4a through 60.482–11a, except as provided in § 60.5401a.

(b) You may elect to comply with the requirements of §§ 60.483–1a and 60.483–2a, as an alternative.

(c) You may apply to the Administrator for permission to use an alternative means of emission limitation that achieves a reduction in emissions of methane and VOC at least equivalent to that achieved by the controls required in this subpart according to the requirements of § 60.5402a.

(d) You must comply with the provisions of § 60.485a except as provided in paragraph (f) of this section.

(e) You must comply with the provisions of §§ 60.486a and 60.487a of this part except as provided in §§ 60.5401a, 60.5421a, and 60.5422a.

(f) You must use the following provision instead of § 60.485a(d)(1): Each piece of equipment is presumed to be in VOC service or in wet gas service unless an owner or operator demonstrates that the piece of equipment is not in VOC service or in wet gas service. For a piece of equipment to be considered not in VOC service, it must be determined that the VOC content can be reasonably expected never to exceed 10.0 percent by weight. For a piece of equipment to be considered in wet gas service, it must be determined that it contains or contacts the field gas before the extraction step in the process. For purposes of determining the percent VOC content of the process fluid that is contained in or contacts a piece of equipment, procedures that conform to the methods described in ASTM E169–93, E168–92, or E260–96 (incorporated by reference as specified in § 60.17) must be used.

§ 60.5401a What are the exceptions to the methane and VOC equipment leak standards for affected facilities at onshore natural gas processing plants?

(a) You may comply with the following exceptions to the provisions of § 60.5400a(a) and (b).

(b)(1) Each pressure relief device in gas/vapor service may be monitored quarterly and within 5 days after each pressure release to detect leaks by the methods specified in § 60.485a(b) except as provided in § 60.5400a(c) and in paragraph (b)(4) of this section, and § 60.482–4a(a) through (c) of subpart VVa of this part.

(2) If an instrument reading of 500 ppm or greater is measured, a leak is detected.

(3)(i) When a leak is detected, it must be repaired as soon as practicable, but no later than 15 calendar days after it is detected, except as provided in § 60.482–9a.

(ii) A first attempt at repair must be made no later than 5 calendar days after each leak is detected.

(4)(i) Any pressure relief device that is located in a nonfractionating plant that is monitored only by non-plant personnel may be monitored after a pressure release the next time the monitoring personnel are on-site, instead of within 5 days as specified in paragraph (b)(1) of this section and § 60.482–4a(b)(1) of subpart VVa of this part.

(ii) No pressure relief device described in paragraph (b)(4)(i) of this section may be allowed to operate for more than 30 days after a pressure release without monitoring.

(c) Sampling connection systems are exempt from the requirements of § 60.482–5a.

(d) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service that are located at a nonfractionating plant that does not have the design capacity to process 283,200 standard cubic meters per day (scmd) (10 million standard cubic feet per day) or more of field gas are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(e) Pumps in light liquid service, valves in gas/vapor and light liquid service, pressure relief devices in gas/vapor service, and connectors in gas/vapor service and in light liquid service within a process unit that is located in the Alaskan North Slope are exempt from the routine monitoring requirements of §§ 60.482–2a(a)(1), 60.482–7a(a), 60.482–11a(a), and paragraph (b)(1) of this section.

(f) An owner or operator may use the following provisions instead of § 60.485a(e):

(1) Equipment is in heavy liquid service if the weight percent evaporated is 10 percent or less at 150 °C (302 °F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(2) Equipment is in light liquid service if the weight percent evaporated is greater than 10 percent at 150 °C (302

°F) as determined by ASTM Method D86–96 (incorporated by reference as specified in § 60.17).

(g) An owner or operator may use the following provisions instead of § 60.485a(b)(2): A calibration drift assessment shall be performed, at a minimum, at the end of each monitoring day. Check the instrument using the same calibration gas(es) that were used to calibrate the instrument before use. Follow the procedures specified in Method 21 of appendix A–7 of this part, Section 10.1, except do not adjust the meter readout to correspond to the calibration gas value. Record the instrument reading for each scale used as specified in § 60.486a(e)(8). Divide these readings by the initial calibration values for each scale and multiply by 100 to express the calibration drift as a percentage. If any calibration drift assessment shows a negative drift of more than 10 percent from the initial calibration value, then all equipment monitored since the last calibration with instrument readings below the appropriate leak definition and above the leak definition multiplied by (100 minus the percent of negative drift/divided by 100) must be re-monitored. If any calibration drift assessment shows a positive drift of more than 10 percent from the initial calibration value, then, at the owner/operator's discretion, all equipment since the last calibration with instrument readings above the appropriate leak definition and below the leak definition multiplied by (100 plus the percent of positive drift/divided by 100) may be re-monitored.

§ 60.5402a What are the alternative emission limitations for methane and VOC equipment leaks from onshore natural gas processing plants?

(a) If, in the Administrator's judgment, an alternative means of emission limitation will achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under any design, equipment, work practice or operational standard, the Administrator will publish, in the **Federal Register**, a notice permitting the use of that alternative means for the purpose of compliance with that standard. The notice may condition permission on requirements related to the operation and maintenance of the alternative means.

(b) Any notice under paragraph (a) of this section must be published only after notice and an opportunity for a public hearing.

(c) The Administrator will consider applications under this section from either owners or operators of affected facilities, or manufacturers of control equipment.

(d) The Administrator will treat applications under this section according to the following criteria, except in cases where the Administrator concludes that other criteria are appropriate:

(1) The applicant must collect, verify and submit test data, covering a period of at least 12 months, necessary to support the finding in paragraph (a) of this section.

(2) If the applicant is an owner or operator of an affected facility, the applicant must commit in writing to operate and maintain the alternative means so as to achieve a reduction in methane and VOC emissions at least equivalent to the reduction in methane and VOC emissions achieved under the design, equipment, work practice or operational standard.

§ 60.5405a What standards apply to sweetening units at onshore natural gas processing plants?

(a) During the initial performance test required by § 60.8(b), you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_i) to be determined from Table 1 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

(b) After demonstrating compliance with the provisions of paragraph (a) of this section, you must achieve at a minimum, an SO_2 emission reduction efficiency (Z_c) to be determined from Table 2 of this subpart based on the sulfur feed rate (X) and the sulfur content of the acid gas (Y) of the affected facility.

§ 60.5406a What test methods and procedures must I use for my sweetening units affected facilities at onshore natural gas processing plants?

(a) In conducting the performance tests required in § 60.8, you must use the test methods in appendix A of this part or other methods and procedures as specified in this section, except as provided in paragraph § 60.8(b).

(b) During a performance test required by § 60.8, you must determine the minimum required reduction efficiencies (Z) of SO_2 emissions as required in § 60.5405a(a) and (b) as follows:

(1) The average sulfur feed rate (X) must be computed as follows:

$$X = KQ_aY$$

Where:

X = average sulfur feed rate, Mg/D (LT/D).
Q_a = average volumetric flow rate of acid gas from sweetening unit, dscm/day (dscf/day).
Y = average H2S concentration in acid gas feed from sweetening unit, percent by volume, expressed as a decimal.
K = (32 kg S/kg-mole)/((24.04 dscm/kg-mole) (1000 kg S/Mg)).
= 1.331×10^{-3}Mg/dscm, for metric units.
= (32 lb S/lb-mole)/((385.36 dscf/lb-mole) (2240 lb S/long ton)).
= 3.707×10^{-5} long ton/dscf, for English units.

(2) You must use the continuous readings from the process flowmeter to determine the average volumetric flow rate (Q_a) in dscm/day (dscf/day) of the acid gas from the sweetening unit for each run.

(3) You must use the Tutwiler procedure in § 60.5408a or a chromatographic procedure following ASTM E260–96 (incorporated by reference as specified in § 60.17) to determine the H_2S concentration in the acid gas feed from the sweetening unit (Y). At least one sample per hour (at equally spaced intervals) must be taken during each 4-hour run. The arithmetic mean of all samples must be the average H_2S concentration (Y) on a dry basis for the run. By multiplying the result from the Tutwiler procedure by 1.62×10^{-3}, the units gr/100 scf are converted to volume percent.

(4) Using the information from paragraphs (b)(1) and (b)(3) of this section, Tables 1 and 2 of this subpart must be used to determine the required initial (Z_i) and continuous (Z_c) reduction efficiencies of SO_2 emissions.

(c) You must determine compliance with the SO_2 standards in § 60.5405a(a) or (b) as follows:

(1) You must compute the emission reduction efficiency (R) achieved by the sulfur recovery technology for each run using the following equation:

$$R = (100S)/(S + E)$$

(2) You must use the level indicators or manual soundings to measure the liquid sulfur accumulation rate in the product storage vessels. You must use readings taken at the beginning and end of each run, the tank geometry, sulfur density at the storage temperature, and sample duration to determine the sulfur production rate (S) in kg/hr (lb/hr) for each run.

(3) You must compute the emission rate of sulfur for each run as follows:

$$E = C_eQ_{sd}/K\ 1$$

Where:

E = emission rate of sulfur per run, kg/hr.
Ce = concentration of sulfur equivalent (SO^{2+} reduced sulfur), g/dscm (lb/dscf).
Q_{sd} = volumetric flow rate of effluent gas, dscm/hr (dscf/hr).
K_1 = conversion factor, 1000 g/kg (7000 gr/lb).

(4) The concentration (C_e) of sulfur equivalent must be the sum of the SO_2

and TRS concentrations, after being converted to sulfur equivalents. For each run and each of the test methods specified in this paragraph (c) of this section, you must use a sampling time of at least 4 hours. You must use Method 1 of appendix A–1 of this part to select the sampling site. The sampling point in the duct must be at the centroid of the cross-section if the area is less than 5 m^2 (54 ft^2) or at a point no closer to the walls than 1 m (39 in) if the cross-sectional area is 5 m^2 or more, and the centroid is more than 1 m (39 in) from the wall.

(i) You must use Method 6 of appendix A–4 of this part to determine the SO_2 concentration. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration must be multiplied by 0.5×10^{-3} to convert the results to sulfur equivalent. In place of Method 6 of Appendix A of this part, you may use ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17)

(ii) You must use Method 15 of appendix A–5 of this part to determine the TRS concentration from reduction-type devices or where the oxygen content of the effluent gas is less than 1.0 percent by volume. The sampling rate must be at least 3 liters/min (0.1 ft^3/min) to insure minimum residence time in the sample line. You must take sixteen samples at 15-minute intervals. The arithmetic average of all the samples must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iii) You must use Method 16A of appendix A–6 of this part or Method 15 of appendix A–5 of this part or ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the reduced sulfur concentration from oxidation-type devices or where the oxygen content of the effluent gas is greater than 1.0 percent by volume. You must take eight samples of 20 minutes each at 30-minute intervals. The arithmetic average must be the concentration for the run. The concentration in ppm reduced sulfur as sulfur must be multiplied by 1.333×10^{-3} to convert the results to sulfur equivalent.

(iv) You must use Method 2 of appendix A–1 of this part to determine the volumetric flow rate of the effluent gas. A velocity traverse must be conducted at the beginning and end of each run. The arithmetic average of the two measurements must be used to calculate the volumetric flow rate (Q_{sd}) for the run. For the determination of the effluent gas molecular weight, a single integrated sample over the 4-hour period may be taken and analyzed or grab samples at 1-hour intervals may be taken, analyzed, and averaged. For the moisture content, you must take two samples of at least 0.10 dscm (3.5 dscf) and 10 minutes at the beginning of the 4-hour run and near the end of the time period. The arithmetic average of the two runs must be the moisture content for the run.

§ 60.5407a What are the requirements for monitoring of emissions and operations from my sweetening unit affected facilities at onshore natural gas processing plants?

(a) If your sweetening unit affected facility is located at an onshore natural gas processing plant and is subject to the provisions of § 60.5405a(a) or (b) you must install, calibrate, maintain, and operate monitoring devices or perform measurements to determine the following operations information on a daily basis:

(1) *The accumulation of sulfur product over each 24-hour period.* The monitoring method may incorporate the use of an instrument to measure and record the liquid sulfur production rate, or may be a procedure for measuring and recording the sulfur liquid levels in the storage vessels with a level indicator or by manual soundings, with subsequent calculation of the sulfur production rate based on the tank geometry, stored sulfur density, and elapsed time between readings. The method must be designed to be accurate within ±2 percent of the 24-hour sulfur accumulation.

(2) *The H_2S concentration in the acid gas from the sweetening unit for each 24-hour period.* At least one sample per 24-hour period must be collected and analyzed using the equation specified in § 60.5406a(b)(1). The Administrator may require you to demonstrate that the H_2S concentration obtained from one or more samples over a 24-hour period is within ±20 percent of the average of 12 samples collected at equally spaced intervals during the 24-hour period. In instances where the H_2S concentration of a single sample is not within ±20 percent of the average of the 12 equally spaced samples, the Administrator may require a more frequent sampling schedule.

(3) *The average acid gas flow rate from the sweetening unit.* You must install and operate a monitoring device to continuously measure the flow rate of acid gas. The monitoring device reading must be recorded at least once per hour during each 24-hour period. The average acid gas flow rate must be computed from the individual readings.

(4) *The sulfur feed rate (X).* For each 24-hour period, you must compute X using the equation specified in § 60.5406a(b)(1).

(5) *The required sulfur dioxide emission reduction efficiency for the 24-hour period.*You must use the sulfur feed rate and the H_2S concentration in the acid gas for the 24-hour period, as applicable, to determine the required reduction efficiency in accordance with the provisions of § 60.5405a(b).

(b) Where compliance is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device, you must install, calibrate, maintain, and operate monitoring devices and continuous emission monitors as follows:

(1) A continuous monitoring system to measure the total sulfur emission rate (E) of SO_2 in the gases discharged to the atmosphere. The SO_2 emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 percent and 70 percent of the measurement range of the instrument system.

(2) Except as provided in paragraph (b)(3) of this section: A monitoring device to measure the temperature of the gas leaving the combustion zone of the incinerator, if compliance with § 60.5405a(a) is achieved through the use of an oxidation control system or a reduction control system followed by a continually operated incineration device. The monitoring device must be certified by the manufacturer to be accurate to within ±1 percent of the temperature being measured.

(3) When performance tests are conducted under the provision of § 60.8 to demonstrate compliance with the standards under § 60.5405a, the temperature of the gas leaving the incinerator combustion zone must be determined using the monitoring device. If the volumetric ratio of sulfur dioxide to sulfur dioxide plus total reduced sulfur (expressed as SO_2) in the gas leaving the incinerator is equal to or less than 0.98, then temperature monitoring may be used to demonstrate that sulfur dioxide emission monitoring is sufficient to determine total sulfur emissions. At all times during the operation of the facility, you must maintain the average temperature of the gas leaving the combustion zone of the incinerator at or above the appropriate level determined during the most recent performance test to ensure the sulfur

compound oxidation criteria are met. Operation at lower average temperatures may be considered by the Administrator to be unacceptable operation and maintenance of the affected facility. You may request that the minimum incinerator temperature be reestablished by conducting new performance tests under § 60.8.

(4) Upon promulgation of a performance specification of continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants, you may, as an alternative to paragraph (b)(2) of this section, install, calibrate, maintain, and operate a continuous emission monitoring system for total reduced sulfur compounds as required in paragraph (d) of this section in addition to a sulfur dioxide emission monitoring system. The sum of the equivalent sulfur mass emission rates from the two monitoring systems must be used to compute the total sulfur emission rate (E).

(c) Where compliance is achieved through the use of a reduction control system not followed by a continually operated incineration device, you must install, calibrate, maintain, and operate a continuous monitoring system to measure the emission rate of reduced sulfur compounds as SO_2 equivalent in the gases discharged to the atmosphere. The SO_2 equivalent compound emission rate must be expressed in terms of equivalent sulfur mass flow rates (kg/hr (lb/hr)). The span of this monitoring system must be set so that the equivalent emission limit of § 60.5405a(b) will be between 30 and 70 percent of the measurement range of the system. This requirement becomes effective upon promulgation of a performance specification for continuous monitoring systems for total reduced sulfur compounds at sulfur recovery plants.

(d) For those sources required to comply with paragraph (b) or (c) of this section, you must calculate the average sulfur emission reduction efficiency achieved (R) for each 24-hour clock interval. The 24-hour interval may begin and end at any selected clock time, but must be consistent. You must compute the 24-hour average reduction efficiency (R) based on the 24-hour average sulfur production rate (S) and sulfur emission rate (E), using the equation in § 60.5406a(c)(1).

(1) You must use data obtained from the sulfur production rate monitoring device specified in paragraph (a) of this section to determine S.

(2) You must use data obtained from the sulfur emission rate monitoring systems specified in paragraphs (b) or (c) of this section to calculate a 24-hour average for the sulfur emission rate (E). The monitoring system must provide at least one data point in each successive 15-minute interval. You must use at least two data points to calculate each 1-hour average. You must use a minimum of 18 1-hour averages to compute each 24-hour average.

(e) In lieu of complying with paragraphs (b) or (c) of this section, those sources with a design capacity of less than 152 Mg/D (150 LT/D) of H_2S expressed as sulfur may calculate the sulfur emission reduction efficiency achieved for each 24-hour period by:

$$R = \frac{K_2 S}{X}$$

Where:

R = The sulfur dioxide removal efficiency achieved during the 24-hour period, percent.

K_2 = Conversion factor, 0.02400 Mg/D per kg/hr (0.01071 LT/D per lb/hr).

S = The sulfur production rate during the 24-hour period, kg/hr (lb/hr).

X = The sulfur feed rate in the acid gas, Mg/D (LT/D).

(f) The monitoring devices required in paragraphs (b)(1), (b)(3) and (c) of this section must be calibrated at least annually according to the manufacturer's specifications, as required by § 60.13(b).

(g) The continuous emission monitoring systems required in paragraphs (b)(1), (b)(3), and (c) of this section must be subject to the emission monitoring requirements of § 60.13 of the General Provisions. For conducting the continuous emission monitoring system performance evaluation required by § 60.13(c), Performance Specification 2 of appendix B of this part must apply, and Method 6 of appendix A–4 of this part must be used for systems required by paragraph (b) of this section. In place of Method 6 of appendix A–4 of this part, ASME PTC 19.10–1981 (incorporated by reference—see § 60.17) may be used.

§ 60.5408a What is an optional procedure for measuring hydrogen sulfide in acid gas—Tutwiler Procedure?

The Tutwiler procedure may be found in the Gas Engineers Handbook, Fuel Gas Engineering practices, The Industrial Press, 93 Worth Street, New York, NY, 1966, First Edition, Second Printing, page 6/25 (Docket A–80–20–A, Entry II–I–67).

(a) When an instantaneous sample is desired and H_2S concentration is 10 grains per 1000 cubic foot or more, a 100 ml Tutwiler burette is used. For concentrations less than 10 grains, a 500 ml Tutwiler burette and more dilute solutions are used. In principle, this method consists of titrating hydrogen sulfide in a gas sample directly with a standard solution of iodine.

(b) *Apparatus.* (See Figure 1 of this subpart) A 100 or 500 ml capacity Tutwiler burette, with two-way glass stopcock at bottom and three-way stopcock at top which connect either with inlet tubulature or glass-stoppered cylinder, 10 ml capacity, graduated in 0.1 ml subdivision; rubber tubing connecting burette with leveling bottle.

(c) *Reagents.* (1) Iodine stock solution, 0.1N. Weight 12.7 g iodine, and 20 to 25 g cp potassium iodide (KI) for each liter of solution. Dissolve KI in as little water as necessary; dissolve iodine in concentrated KI solution, make up to proper volume, and store in glass-stoppered brown glass bottle.

(2) Standard iodine solution, 1 ml = 0.001771 g I. Transfer 33.7 ml of above 0.1N stock solution into a 250 ml volumetric flask; add water to mark and mix well. Then, for 100 ml sample of gas, 1 ml of standard iodine solution is equivalent to 100 grains H_2S per cubic feet of gas.

(3) Starch solution. Rub into a thin paste about one teaspoonful of wheat starch with a little water; pour into about a pint of boiling water; stir; let cool and decant off clear solution. Make fresh solution every few days.

(d) *Procedure.* Fill leveling bulb with starch solution. Raise (L), open cock (G), open (F) to (A), and close (F) when solutions starts to run out of gas inlet. Close (G). Purge gas sampling line and connect with (A). Lower (L) and open (F) and (G). When liquid level is several ml past the 100 ml mark, close (G) and (F), and disconnect sampling tube. Open (G) and bring starch solution to 100 ml mark by raising (L); then close (G). Open (F) momentarily, to bring gas in burette to atmospheric pressure, and close (F). Open (G), bring liquid level down to 10 ml mark by lowering (L). Close (G), clamp rubber tubing near (E) and disconnect it from burette. Rinse graduated cylinder with a standard iodine solution (0.00171 g I per ml); fill cylinder and record reading. Introduce successive small amounts of iodine through (F); shake well after each addition; continue until a faint permanent blue color is obtained. Record reading; subtract from previous reading, and call difference D.

(e) With every fresh stock of starch solution perform a blank test as follows: Introduce fresh starch solution into burette up to 100 ml mark. Close (F) and (G). Lower (L) and open (G). When liquid level reaches the 10 ml mark, close (G). With air in burette, titrate as during a test and up to same end point. Call ml of iodine used C. Then, Grains H_2S per 100 cubic foot of gas = 100 (D–C)

(f) Greater sensitivity can be attained if a 500 ml capacity Tutwiler burette is used with a more dilute (0.001N) iodine solution. Concentrations less than 1.0 grains per 100 cubic foot can be determined in this way. Usually, the starch-iodine end point is much less distinct, and a blank determination of end point, with H_2S-free gas or air, is required.

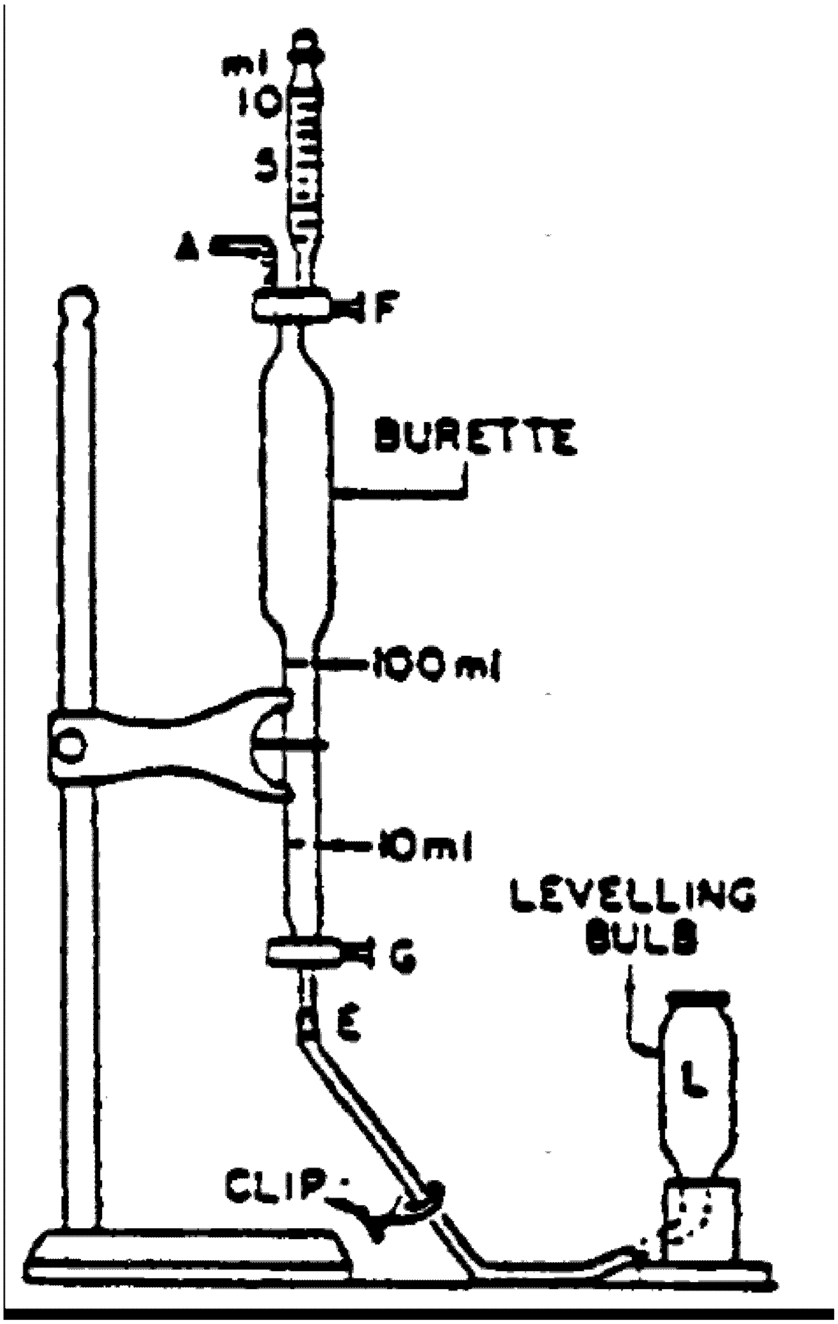

Figure 1. Tutwiler burette (lettered items mentioned in text).

§ 60.5410a How do I demonstrate initial compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, collection of fugitive emissions components at a compressor station, and equipment leaks and sweetening unit affected facilities at onshore natural gas processing plants?

You must determine initial compliance with the standards for each affected facility using the requirements in paragraphs (a) through (j) of this section. The initial compliance period begins on [date 60 days after publication of final rule in the **Federal Register**], or upon initial startup, whichever is later, and ends no later than 1 year after the initial startup date for your affected facility or no later than 1 year after [date 60 days after publication of final rule in the **Federal Register**]. The initial compliance period may be less than one full year.

(a) To achieve initial compliance with the methane and VOC standards for each well completion operation conducted at your well affected facility you must comply with paragraphs (a)(1) through (a)(4) of this section.

(1) You must submit the notification required in § 60.5420a(a)(2).

(2) You must submit the initial annual report for your well affected facility as required in § 60.5420a(b).

(3) You must maintain a log of records as specified in § 60.5420a(c)(1)(i) through (iv) for each well completion operation conducted during the initial compliance period.

(4) For each well affected facility subject to both § 60.5375a(a)(1) and (3), as an alternative to retaining the records specified in § 60.5420a(c)(1)(i) through (iv), you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the well site imbedded within or stored with the digital file showing the equipment for storing or re-injecting recovered liquid, equipment for routing recovered gas to the gas flow line and the completion combustion device (if applicable) connected to and operating at each well completion operation that occurred during the initial compliance period. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the equipment connected and operating at each well completion operation with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(b)(1) To achieve initial compliance with standards for your centrifugal compressor affected facility you must reduce methane and VOC emissions from each centrifugal compressor wet seal fluid degassing system by 95.0 percent or greater as required by § 60.5380a and as demonstrated by the requirements of § 60.5413a.

(2) If you use a control device to reduce emissions, you must equip the wet seal fluid degassing system with a cover that meets the requirements of § 60.5411a(b) that is connected through a closed vent system that meets the requirements of § 60.5411a(a) and is routed to a control device that meets the conditions specified in § 60.5412a(a), (b) and (c). As an alternative to routing the closed vent system to a control device, you may route the closed vent system to a process that reduces VOC emissions by at least 95.0 percent.

(3) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or by [date 60 days after publication of final rule in the **Federal Register**], whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(b)(1) through (3).

(4) You must conduct the initial inspections required in § 60.5416a(a) and (b).

(5) You must install and operate the continuous parameter monitoring systems in accordance with § 60.5417a(a) through (g), as applicable.

(6) You must submit the notifications required in 60.7(a)(1), (3), and (4).

(7) You must submit the initial annual report for your centrifugal compressor affected facility as required in § 60.5420a(b) for each centrifugal compressor affected facility.

(8) You must maintain the records as specified in § 60.5420a(c).

(c) To achieve initial compliance with the standards for each reciprocating compressor affected facility you must comply with paragraphs (c)(1) through (4) of this section.

(1) If complying with § 60.5385a(a)(1) or (2), during the initial compliance period, you must continuously monitor the number of hours of operation or track the number of months since the last rod packing replacement.

(2) If complying with § 60.5385a(a)(3), you must operate the rod packing emissions collection system under negative pressure and route emissions to a process through a closed vent system that meets the requirements of § 60.5411a(a).

(3) You must submit the initial annual report for your reciprocating compressor as required in § 60.5420a(b).

(4) You must maintain the records as specified in § 60.5420a(c) for each reciprocating compressor affected facility.

(d) To achieve initial compliance with methane and VOC emission standards for your pneumatic controller affected facility you must comply with the requirements specified in paragraphs (d)(1) through (6) of this section, as applicable.

(1) You must demonstrate initial compliance by maintaining records as specified in § 60.5420a(c)(4)(ii) of your determination that the use of a pneumatic controller affected facility with a bleed rate greater than the applicable standard is required as specified in § 60.5390a(a).

(2) You own or operate a pneumatic controller affected facility located at a natural gas processing plant and your pneumatic controller is driven by a gas other than natural gas and therefore emits zero natural gas.

(3) You own or operate a pneumatic controller affected facility located other than at a natural gas processing plant and the manufacturer's design specifications indicate that the controller emits less than or equal to 6 standard cubic feet of gas per hour.

(4) You must tag each new pneumatic controller affected facility according to the requirements of § 60.5390a(b)(2) or (c)(2).

(5) You must include the information in paragraph (d)(1) of this section and a listing of the pneumatic controller affected facilities specified in paragraphs (d)(2) and (3) of this section in the initial annual report submitted for your pneumatic controller affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b).

(6) You must maintain the records as specified in § 60.5420a(c) for each pneumatic controller affected facility.

(e) To achieve initial compliance with emission standards for your pneumatic pump affected facility you must comply with the requirements specified in paragraphs (e)(1) through (6) of this section, as applicable.

(1) You own or operate a pneumatic pump affected facility located at a natural gas processing plant and your pneumatic pump is driven by a gas other than natural gas and therefore emits zero natural gas.

(2) You own or operate a pneumatic pump affected facility located other than at a natural gas processing plant and your pneumatic pump is controlled by at least 95 percent.

(3) You own or operate a pneumatic pump affected facility located other

than at a natural gas processing plant and your pneumatic pump is not controlled by at least 95 percent because a control device is not available at the site, you must submit the certification in 60.5420a(b)(8)(i).

(4) You must tag each new pneumatic pump affected facility according to the requirements of § 60.5393a(a)(2) or (b)(3).

(5) You must include a listing of the pneumatic pump affected facilities specified in paragraphs (e)(1) through (3) of this section in the initial annual report submitted for your pneumatic pump affected facilities constructed, modified or reconstructed during the period covered by the annual report according to the requirements of § 60.5420a(b).

(6) You must maintain the records as specified in § 60.5420a(c) for each pneumatic pump affected facility.

(f) For affected facilities at onshore natural gas processing plants, initial compliance with the methane and VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For sweetening unit affected facilities at onshore natural gas processing plants, initial compliance is demonstrated according to paragraphs (g)(1) through (3) of this section.

(1) To determine compliance with the standards for SO_2 specified in § 60.5405a(a), during the initial performance test as required by § 60.8, the minimum required sulfur dioxide emission reduction efficiency (Z_i) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology as specified in paragraphs (g)(1)(i) and (ii) of this section.

(i) If $R \geq Z_i$, your affected facility is in compliance.

(ii) If $R < Z_i$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(3) You have submitted the results of paragraphs (g)(1) and (2) of this section in the initial annual report submitted for your sweetening unit affected facilities at onshore natural gas processing plants.

(h) For each storage vessel affected facility, you must comply with paragraphs (h)(1) through (6) of this section. You must demonstrate initial compliance by [date 60 days after publication of final rule in the **Federal Register**], or within 60 days after startup, whichever is later.

(1) You must determine the potential VOC emission rate as specified in § 60.5365a(e).

(2) You must reduce VOC emissions in accordance with § 60.5395a(a).

(3) If you use a control device to reduce emissions, you must equip the storage vessel with a cover that meets the requirements of § 60.5411a(b) and is connected through a closed vent system that meets the requirements of § 60.5411a(c) to a control device that meets the conditions specified in § 60.5412a(d) within 60 days after startup for storage vessels constructed, modified or reconstructed at well sites with no other wells in production, or upon startup for storage vessels constructed, modified or reconstructed at well sites with one or more wells already in production.

(4) You must conduct an initial performance test as required in § 60.5413a within 180 days after initial startup or within 180 days of [date 60 days after publication of final rule in the **Federal Register**], whichever is later, and you must comply with the continuous compliance requirements in § 60.5415a(e).

(5) You must submit the information required for your storage vessel affected facility as specified in § 60.5420a(b).

(6) You must maintain the records required for your storage vessel affected facility, as specified in § 60.5420a(c) for each storage vessel affected facility.

(i) For each storage vessel affected facility, you must submit the notification specified in § 60.5395a(b)(2) with the initial annual report specified in § 60.5420a(b).

(j) To achieve initial compliance with the fugitive emission standards for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must comply with paragraphs (j)(1) through (5) of this section.

(1) You must develop a fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5397a(a).

(2) You must conduct an initial monitoring survey as required in § 60.5397a(f).

(3) You must maintain the records specified in § 60.5420a(c).

(4) You must repair each identified source of fugitive emissions for each affected facility as required in § 60.5397a(j).

(5) You must submit the initial annual report for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b).

§ 60.5411a What additional requirements must I meet to determine initial compliance for my covers and closed vent systems routing emissions from centrifugal compressor wet seal fluid degassing systems, reciprocating compressors, pneumatic pumps and storage vessels?

You must meet the applicable requirements of this section for each cover and closed vent system used to comply with the emission standards for your centrifugal compressor wet seal degassing systems, reciprocating compressors, pneumatic pumps and storage vessels.

(a) *Closed vent system requirements for reciprocating compressors, centrifugal compressor wet seal degassing systems and pneumatic pumps.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the reciprocating compressor rod packing emissions collection system, the wet seal fluid degassing system or pneumatic pump to a control device or to a process that meets the requirements specified in § 60.5412a(a) through (c).

(2) You must design and operate the closed vent system with no detectable emissions as demonstrated by § 60.5416a(b).

(3) You must meet the requirements specified in paragraphs (a)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device.

(i) Except as provided in paragraph (a)(3)(ii) of this section, you must comply with either paragraph (a)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is activated according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (a)(3)(i) of this section.

(b) *Cover requirements for storage vessels and centrifugal compressor wet seal fluid degassing systems.* (1) The cover and all openings on the cover (*e.g.,* access hatches, sampling ports, pressure relief devices and gauge wells) shall form a continuous impermeable barrier over the entire surface area of the liquid in the storage vessel or wet seal fluid degassing system.

(2) Each cover opening shall be secured in a closed, sealed position (*e.g.,* covered by a gasketed lid or cap) whenever material is in the unit on which the cover is installed except during those times when it is necessary to use an opening as follows:

(i) To add material to, or remove material from the unit (this includes openings necessary to equalize or balance the internal pressure of the unit following changes in the level of the material in the unit);

(ii) To inspect or sample the material in the unit;

(iii) To inspect, maintain, repair, or replace equipment located inside the unit; or

(iv) To vent liquids, gases, or fumes from the unit through a closed-vent system designed and operated in accordance with the requirements of paragraph (a) or (c) of this section to a control device or to a process.

(3) Each storage vessel thief hatch shall be equipped, maintained and operated with a weighted mechanism or equivalent, to ensure that the lid remains properly seated and sealed under normal operating conditions, including such times when working, standing/breathing, and flash emissions may be generated. You must select gasket material for the hatch based on composition of the fluid in the storage vessel and weather conditions.

(c) *Closed vent system requirements for storage vessel affected facilities using a control device or routing emissions to a process.* (1) You must design the closed vent system to route all gases, vapors, and fumes emitted from the material in the storage vessel to a control device that meets the requirements specified in § 60.5412a(c) and (d), or to a process.

(2) You must design and operate a closed vent system with no detectable emissions, as determined using olfactory, visual and auditory inspections. Each closed vent system that routes emissions to a process must be operational 95 percent of the year or greater.

(3) You must meet the requirements specified in paragraphs (c)(3)(i) and (ii) of this section if the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device or to a process.

(i) Except as provided in paragraph (c)(3)(ii) of this section, you must comply with either paragraph (c)(3)(i)(A) or (B) of this section for each bypass device.

(A) You must properly install, calibrate, maintain, and operate a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger and audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420a(c)(8).

(B) You must secure the bypass device valve installed at the inlet to the bypass device in the non-diverting position using a car-seal or a lock-and-key type configuration.

(ii) Low leg drains, high point bleeds, analyzer vents, open-ended valves or lines, and safety devices are not subject to the requirements of paragraph (c)(3)(i) of this section.

§ 60.5412a What additional requirements must I meet for determining initial compliance with control devices used to comply with the emission standards for my centrifugal compressor, pneumatic pump and storage vessel affected facilities?

You must meet the applicable requirements of this section for each control device used to comply with the emission standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility.

(a) Each control device used to meet the emission reduction standard in § 60.5380a(a)(1) for your centrifugal compressor affected facility or § 60.5393a(b)(1) for your pneumatic pump must be installed according to paragraphs (a)(1) through (3) of this section. As an alternative, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e).

(1) Each combustion device (*e.g.,* thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (a)(1)(i) through (iv) of this section.

(i) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a.

(ii) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413a.

(iii) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413a.

(iv) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.,* carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a. As an alternative to the performance testing requirements, you may demonstrate initial compliance by conducting a design analysis for vapor recovery devices according to the requirements of § 60.5413a(c).

(3) You must design and operate a flare in accordance with the requirements of § 60.5413a(a)(1).

(b) You must operate each control device installed on your centrifugal compressor or pneumatic pump affected facility in accordance with the requirements specified in paragraphs (b)(1) and (2) of this section.

(1) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the wet seal fluid degassing system affected facility as required under § 60.5380a(a), or from the pneumatic pump as required under § 60.5393a(b)(1), through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

(2) For each control device monitored in accordance with the requirements of § 60.5417a(a) through (g), you must demonstrate compliance according to the requirements of § 60.5415a(b)(2), as applicable.

(c) For each carbon adsorption system used as a control device to meet the requirements of paragraph (a)(2) or (d)(2) of this section, you must manage the carbon in accordance with the requirements specified in paragraphs (c)(1) or (2) of this section.

(1) Following the initial startup of the control device, you must replace all carbon in the control device with fresh carbon on a regular, predetermined time interval that is no longer than the carbon service life established according to § 60.5413a(c)(2) or (3) or according to the design required in paragraph (d)(2) of this section, for the carbon adsorption system. You must maintain records identifying the schedule for replacement and records of each carbon replacement as required in § 60.5420a(c)(10) and (12).

(2) You must either regenerate, reactivate, or burn the spent carbon removed from the carbon adsorption system in one of the units specified in paragraphs (c)(2)(i) through (vii) of this section.

(i) Regenerate or reactivate the spent carbon in a thermal treatment unit for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart X.

(ii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating air emission controls in accordance with this section.

(iii) Regenerate or reactivate the spent carbon in a thermal treatment unit equipped with and operating organic air emission controls in accordance with an emissions standard for VOC under another subpart in 40 CFR part 60 or this part.

(iv) Burn the spent carbon in a hazardous waste incinerator for which the owner or operator has been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 264, subpart O.

(v) Burn the spent carbon in a hazardous waste incinerator which you have designed and operated in accordance with the requirements of 40 CFR part 265, subpart O.

(vi) Burn the spent carbon in a boiler or industrial furnace for which you have been issued a final permit under 40 CFR part 270 that implements the requirements of 40 CFR part 266, subpart H.

(vii) Burn the spent carbon in a boiler or industrial furnace that you have designed and operated in accordance with the interim status requirements of 40 CFR part 266, subpart H.

(d) Each control device used to meet the emission reduction standard in § 60.5395a(a) for your storage vessel affected facility must be installed according to paragraphs (d)(1) through (3) of this section, as applicable. As an alternative to paragraph (d)(1) of this section, you may install a control device model tested under § 60.5413a(d), which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e).

(1) For each enclosed combustion control device (e.g., thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) you must meet the requirements in paragraphs (d)(1)(i) through (iv) of this section.

(i) Ensure that each enclosed combustion control device is maintained in a leak free condition.

(ii) Install and operate a continuous burning pilot flame.

(iii) Operate the combustion control device with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period. A visible emissions test using section 11 of EPA Method 22 of appendix A–7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes. Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All inspection, repair and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection. Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A–7 of this part visual observation as described in this paragraph.

(iv) Each combustion control device (*e.g.*, thermal vapor incinerator, catalytic vapor incinerator, boiler, or process heater) must be designed and operated in accordance with one of the performance requirements specified in paragraphs (A) through (D) of this section.

(A) You must reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater as determined in accordance with the requirements of § 60.5413a.

(B) You must reduce the concentration of TOC in the exhaust gases at the outlet to the device to a level equal to or less than 600 parts per million by volume as propane on a dry basis corrected to 3 percent oxygen as determined in accordance with the requirements of § 60.5413a.

(C) You must operate at a minimum temperature of 760 °C for a control device that can demonstrate a uniform combustion zone temperature during the performance test conducted under § 60.5413a.

(D) If a boiler or process heater is used as the control device, then you must introduce the vent stream into the flame zone of the boiler or process heater.

(2) Each vapor recovery device (*e.g.*, carbon adsorption system or condenser) or other non-destructive control device must be designed and operated to reduce the mass content of methane and VOC in the gases vented to the device by 95.0 percent by weight or greater. A carbon replacement schedule must be included in the design of the carbon adsorption system.

(3) You must operate each control device used to comply with this subpart at all times when gases, vapors, and fumes are vented from the storage vessel affected facility through the closed vent system to the control device. You may vent more than one affected facility to a control device used to comply with this subpart.

§ 60.5413a What are the performance testing procedures for control devices used to demonstrate compliance at my centrifugal compressor, pneumatic pump and storage vessel affected facilities?

This section applies to the performance testing of control devices used to demonstrate compliance with the emissions standards for your centrifugal compressor affected facility, pneumatic pump affected facility, or storage vessel affected facility. You must demonstrate that a control device achieves the performance requirements of § 60.5412a(a) or (d) using the performance test methods and procedures specified in this section. For condensers and carbon adsorbers, you may use a design analysis as specified in paragraph (c) of this section in lieu of complying with paragraph (b) of this section. In addition, this section contains the requirements for enclosed combustion control device performance tests conducted by the manufacturer applicable to storage vessel, centrifugal compressor and pneumatic pump affected facilities.

(a) *Performance test exemptions.* You are exempt from the requirements to conduct performance tests and design analyses if you use any of the control devices described in paragraphs (a)(1) through (7) of this section.

(1) A flare that is designed and operated in accordance with § 60.18(b). You must conduct the compliance determination using Method 22 of appendix A–7 of this part to determine visible emissions.

(2) A boiler or process heater with a design heat input capacity of 44 megawatts or greater.

(3) A boiler or process heater into which the vent stream is introduced with the primary fuel or is used as the primary fuel.

(4) A boiler or process heater burning hazardous waste for which you have either been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 266, subpart H; or you have certified compliance with the interim status requirements of 40 CFR part 266, subpart H.

(5) A hazardous waste incinerator for which you have been issued a final permit under 40 CFR part 270 and comply with the requirements of 40 CFR part 264, subpart O; or you have certified compliance with the interim status requirements of 40 CFR part 265, subpart O.

(6) A performance test is waived in accordance with § 60.8(b).

(7) A control device whose model can be demonstrated to meet the performance requirements of § 60.5412a(a) or (d) through a performance test conducted by the manufacturer, as specified in paragraph (d) of this section.

(b) *Test methods and procedures.* You must use the test methods and procedures specified in paragraphs (b)(1) through (5) of this section, as applicable, for each performance test conducted to demonstrate that a control device meets the requirements of § 60.5412a(a) or (d). You must conduct the initial and periodic performance tests according to the schedule specified in paragraph (b)(5) of this section.

(1) You must use Method 1 or 1A of appendix A–1 of this part, as appropriate, to select the sampling sites specified in paragraphs (b)(1)(i) and (ii) of this section. Any references to particulate mentioned in Methods 1 and 1A do not apply to this section.

(i) Sampling sites must be located at the inlet of the first control device, and at the outlet of the final control device, to determine compliance with the control device percent reduction requirement specified in § 60.5412a(a)(1)(i) or (a)(2).

(ii) The sampling site must be located at the outlet of the combustion device to determine compliance with the enclosed combustion control device total TOC concentration limit specified in § 60.5412a(a)(1)(ii).

(2) You must determine the gas volumetric flowrate using Method 2, 2A, 2C, or 2D of appendix A–2 of this part, as appropriate.

(3) To determine compliance with the control device percent reduction performance requirement in § 60.5412a(a)(1)(i), (a)(2) or (d)(1)(i)(A), you must use Method 25A of appendix A–7 of this part. You must use the procedures in paragraphs (b)(3)(i) through (iv) of this section to calculate percent reduction efficiency.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must compute the mass rate of TOC (minus methane and ethane) using the equations and procedures specified in paragraphs (b)(3)(ii)(A) and (B) of this section.

(A) You must use the following equations:

$$E_i = K_2 \left(\sum_{j=1}^{n} C_{ij} M_{ij} \right) Q_i$$

$$E_o = K_2 \left(\sum_{j=1}^{n} C_{oj} M_{oj} \right) Q_o$$

Where:

E_i, E_o = Mass rate of TOC (minus methane and ethane) at the inlet and outlet of the control device, respectively, dry basis, kilogram per hour.

K_2 = Constant, 2.494×10^{-6} (parts per million) (gram-mole per standard cubic meter) (kilogram/gram) (minute/hour), where standard temperature (gram-mole per standard cubic meter) is 20 °C.

C_{ij}, C_{oj} = Concentration of sample component j of the gas stream at the inlet and outlet of the control device, respectively, dry basis, parts per million by volume.

M_{ij}, M_{oj} = Molecular weight of sample component j of the gas stream at the inlet and outlet of the control device, respectively, gram/gram-mole.

Q_i, Q_o = Flowrate of gas stream at the inlet and outlet of the control device, respectively, dry standard cubic meter per minute.

n = Number of components in sample.

(B) When calculating the TOC mass rate, you must sum all organic compounds (minus methane and ethane) measured by Method 25A of appendix A–7 of this part using the equations in paragraph (b)(3)(ii)(A) of this section.

(iii) You must calculate the percent reduction in TOC (minus methane and ethane) as follows:

$$R_{cd} = \frac{E_i - E_o}{E_i} * 100\%$$

Where:

R_{cd} = Control efficiency of control device, percent.

E_i = Mass rate of TOC (minus methane and ethane) at the inlet to the control device as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour or kilograms HAP per hour.

E_o = Mass rate of TOC (minus methane and ethane) at the outlet of the control device, as calculated under paragraph (b)(3)(ii) of this section, kilograms TOC per hour per hour.

(iv) If the vent stream entering a boiler or process heater with a design capacity less than 44 megawatts is introduced with the combustion air or as a secondary fuel, you must determine the weight-percent reduction of total TOC (minus methane and ethane) across the device by comparing the TOC (minus methane and ethane) in all combusted vent streams and primary and secondary fuels with the TOC (minus methane and ethane) exiting the device, respectively.

(4) You must use Method 25A of appendix A–7 of this part to measure TOC (minus methane and ethane) to determine compliance with the enclosed combustion control device total VOC concentration limit specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B). You must calculate parts per million by volume concentration and correct to 3 percent oxygen, using the procedures in paragraphs (b)(4)(i) through (iii) of this section.

(i) For each run, you must take either an integrated sample or a minimum of four grab samples per hour. If grab sampling is used, then the samples must be taken at approximately equal intervals in time, such as 15-minute intervals during the run.

(ii) You must calculate the TOC concentration for each run as follows:

$$C_{TOC} = \sum_{i=1}^{x} \frac{\left(\sum_{j=i}^{n} C_{ji} \right)}{x}$$

Where:

C_{TOC} = Concentration of total organic compounds minus methane and ethane, dry basis, parts per million by volume.

C_{ji} = Concentration of sample component j of sample i, dry basis, parts per million by volume.

n = Number of components in the sample.

x = Number of samples in the sample run.

(iii) You must correct the TOC concentration to 3 percent oxygen as specified in paragraphs (b)(4)(iii)(A) and (B) of this section.

(A) You must use the emission rate correction factor for excess air, integrated sampling and analysis procedures of Method 3A or 3B of appendix A–2 of this part, ASTM D6522–00 (Reapproved 2005), or ASME/

ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17) to determine the oxygen concentration. The samples must be taken during the same time that the samples are taken for determining TOC concentration.

(B) You must correct the TOC concentration for percent oxygen as follows:

$$C_c = C_m\left(\frac{17.9}{20.9 - \%O_{2d}}\right)$$

Where:

C_c = TOC concentration corrected to 3 percent oxygen, dry basis, parts per million by volume.

C_m = TOC concentration, dry basis, parts per million by volume.

$\%O_{2d}$ = Concentration of oxygen, dry basis, percent by volume.

(5) You must conduct performance tests according to the schedule specified in paragraphs (b)(5)(i) and (ii) of this section.

(i) You must conduct an initial performance test within 180 days after initial startup for your affected facility. You must submit the performance test results as required in § 60.5420a(b)(9).

(ii) You must conduct periodic performance tests for all control devices required to conduct initial performance tests except as specified in paragraphs (b)(5)(ii)(A) and (B) of this section. You must conduct the first periodic performance test no later than 60 months after the initial performance test required in paragraph (b)(5)(i) of this section. You must conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test or whenever you desire to establish a new operating limit. You must submit the periodic performance test results as specified in § 60.5420a(b)(9). Combustion control devices meeting the criteria in either paragraph (b)(5)(ii)(A) or (B) of this section are not required to conduct periodic performance tests.

(A) A control device whose model is tested under, and meets the criteria of paragraph (d) of this section.

(B) A combustion control device tested under paragraph (b) of this section that meets the outlet TOC performance level specified in § 60.5412a(a)(1)(ii) or (d)(1)(iv)(B) and that establishes a correlation between firebox or combustion chamber temperature and the TOC performance level.

(c) *Control device design analysis to meet the requirements of § 60.5412a(a)(2) or (d)(2).* (1) For a condenser, the design analysis must include an analysis of the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and must establish the design outlet organic compound concentration level, design average temperature of the condenser exhaust vent stream, and the design average temperatures of the coolant fluid at the condenser inlet and outlet.

(2) For a regenerable carbon adsorption system, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, adsorption cycle time, number and capacity of carbon beds, type and working capacity of activated carbon used for the carbon beds, design total regeneration stream flow over the period of each complete carbon bed regeneration cycle, design carbon bed temperature after regeneration, design carbon bed regeneration time, and design service life of the carbon.

(3) For a nonregenerable carbon adsorption system, such as a carbon canister, the design analysis shall include the vent stream composition, constituent concentrations, flowrate, relative humidity, and temperature, and shall establish the design exhaust vent stream organic compound concentration level, capacity of the carbon bed, type and working capacity of activated carbon used for the carbon bed, and design carbon replacement interval based on the total carbon working capacity of the control device and source operating schedule. In addition, these systems shall incorporate dual carbon canisters in case of emission breakthrough occurring in one canister.

(4) If you and the Administrator do not agree on a demonstration of control device performance using a design analysis, then you must perform a performance test in accordance with the requirements of paragraph (b) of this section to resolve the disagreement. The Administrator may choose to have an authorized representative observe the performance test.

(d) *Performance testing for combustion control devices—manufacturers' performance test.* (1) This paragraph applies to the performance testing of a combustion control device conducted by the device manufacturer. The manufacturer must demonstrate that a specific model of control device achieves the performance requirements in paragraph (d)(11) of this section by conducting a performance test as specified in paragraphs (d)(2) through (10) of this section. You must submit a test report for each combustion control device in accordance with the requirements in paragraph (d)(12) of this section.

(2) Performance testing must consist of three 1-hour (or longer) test runs for each of the four firing rate settings specified in paragraphs (d)(2)(i) through (iv) of this section, making a total of 12 test runs per test. Propene (propylene) gas must be used for the testing fuel. All fuel analyses must be performed by an independent third-party laboratory (not affiliated with the control device manufacturer or fuel supplier).

(i) 90–100 percent of maximum design rate (fixed rate).

(ii) 70–100–70 percent (ramp up, ramp down). Begin the test at 70 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 100 percent of the maximum design rate. Hold at 100 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 70 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iii) 30–70–30 percent (ramp up, ramp down). Begin the test at 30 percent of the maximum design rate. During the first 5 minutes, incrementally ramp the firing rate to 70 percent of the maximum design rate. Hold at 70 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to 30 percent of the maximum design rate. Repeat three more times for a total of 60 minutes of sampling.

(iv) 0–30–0 percent (ramp up, ramp down). Begin the test at the minimum firing rate. During the first 5 minutes, incrementally ramp the firing rate to 30 percent of the maximum design rate. Hold at 30 percent for 5 minutes. In the 10–15 minute time range, incrementally ramp back down to the minimum firing rate. Repeat three more times for a total of 60 minutes of sampling.

(3) All models employing multiple enclosures must be tested simultaneously and with all burners operational. Results must be reported for each enclosure individually and for the average of the emissions from all interconnected combustion enclosures/chambers. Control device operating data must be collected continuously throughout the performance test using an electronic Data Acquisition System. A graphic presentation or strip chart of the control device operating data and emissions test data must be included in the test report in accordance with paragraph (d)(12) of this section. Inlet fuel meter data may be manually recorded provided that all inlet fuel data readings are included in the final report.

(4) Inlet testing must be conducted as specified in paragraphs (d)(4)(i) through (ii) of this section.

(i) The inlet gas flow metering system must be located in accordance with Method 2A of appendix A–1 of this part (or other approved procedure) to measure inlet gas flow rate at the control device inlet location. You must position the fitting for filling fuel sample containers a minimum of eight pipe diameters upstream of any inlet gas flow monitoring meter.

(ii) Inlet flow rate must be determined using Method 2A of appendix A–1 of this part. Record the start and stop reading for each 60-minute THC test. Record the gas pressure and temperature at 5-minute intervals throughout each 60-minute test.

(5) Inlet gas sampling must be conducted as specified in paragraphs (d)(5)(i) through (ii) of this section.

(i) At the inlet gas sampling location, securely connect a Silonite-coated stainless steel evacuated canister fitted with a flow controller sufficient to fill the canister over a 3-hour period. Filling must be conducted as specified in paragraphs (d)(5)(i)(A) through (C) of this section.

(A) Open the canister sampling valve at the beginning of each test run, and close the canister at the end of each test run.

(B) Fill one canister across the three test runs such that one composite fuel sample exists for each test condition.

(C) Label the canisters individually and record sample information on a chain of custody form.

(ii) Analyze each inlet gas sample using the methods in paragraphs (d)(5)(ii)(A) through (C) of this section. You must include the results in the test report required by paragraph (d)(12) of this section.

(A) Hydrocarbon compounds containing between one and five atoms of carbon plus benzene using ASTM D1945–03.

(B) Hydrogen (H2), carbon monoxide (CO), carbon dioxide (CO_2), nitrogen (N_2), oxygen (O_2) using ASTM D1945–03.

(C) Higher heating value using ASTM D3588–98 or ASTM D4891–89.

(6) Outlet testing must be conducted in accordance with the criteria in paragraphs (d)(6)(i) through (v) of this section.

(i) Sample and flow rate must be measured in accordance with paragraphs (d)(6)(i)(A) through (B) of this section.

(A) The outlet sampling location must be a minimum of four equivalent stack diameters downstream from the highest peak flame or any other flow disturbance, and a minimum of one equivalent stack diameter upstream of the exit or any other flow disturbance. A minimum of two sample ports must be used.

(B) Flow rate must be measured using Method 1 of appendix A–1 of this part for determining flow measurement traverse point location, and Method 2 of appendix A–1 of this part for measuring duct velocity. If low flow conditions are encountered (*i.e.*, velocity pressure differentials less than 0.05 inches of water) during the performance test, a more sensitive manometer must be used to obtain an accurate flow profile.

(ii) Molecular weight and excess air must be determined as specified in paragraph (d)(7) of this section.

(iii) Carbon monoxide must be determined as specified in paragraph (d)(8) of this section.

(iv) THC must be determined as specified in paragraph (d)(9) of this section.

(v) Visible emissions must be determined as specified in paragraph (d)(10) of this section.

(7) Molecular weight and excess air determination must be performed as specified in paragraphs (d)(7)(i) through (iii) of this section.

(i) An integrated bag sample must be collected during the moisture test required by Method 4 of appendix A–3 of this part following the procedure specified in (d)(7)(i)(A) and (B) of this section. Analyze the bag sample using a gas chromatograph-thermal conductivity detector (GC–TCD) analysis meeting the criteria in paragraphs (d)(7)(i)(C) and (D) of this section.

(A) Collect the integrated sample throughout the entire test, and collect representative volumes from each traverse location.

(B) Purge the sampling line with stack gas before opening the valve and beginning to fill the bag. Clearly label each bag and record sample information on a chain of custody form.

(C) The bag contents must be vigorously mixed prior to the gas chromatograph analysis.

(D) The GC–TCD calibration procedure in Method 3C of appendix A–2 of this part must be modified by using EPA Alt-045 as follows: For the initial calibration, triplicate injections of any single concentration must agree within 5 percent of their mean to be valid. The calibration response factor for a single concentration re-check must be within 10 percent of the original calibration response factor for that concentration. If this criterion is not met, repeat the initial calibration using at least three concentration levels.

(ii) Calculate and report the molecular weight of oxygen, carbon dioxide, methane, and nitrogen in the integrated bag sample and include in the test report specified in paragraph (d)(12) of this section. Moisture must be determined using Method 4 of appendix A–3 of this part. Traverse both ports with the sampling train required by Method 4 of appendix A–3 of this part during each test run. Ambient air must not be introduced into the integrated bag sample required by Method 3C of appendix A–2 of this part during the port change.

(iii) Excess air must be determined using resultant data from the EPA Method 3C tests and EPA Method 3B of appendix A–2 of this part, equation 3B–1, or ASME/ANSI PTC 19.10–1981, Part 10 (manual portion only) (incorporated by reference as specified in § 60.17).

(8) Carbon monoxide must be determined using Method 10 of appendix A–4 of this part. Run the test simultaneously with Method 25A of appendix A–7 of this part using the same sampling points. An instrument range of 0–10 parts per million by volume-dry (ppmvd) is recommended.

(9) Total hydrocarbon determination must be performed as specified by in paragraphs (d)(9)(i) through (vii) of this section.

(i) Conduct THC sampling using Method 25A of appendix A–7 of this part, except that the option for locating the probe in the center 10 percent of the stack is not allowed. The THC probe must be traversed to 16.7 percent, 50 percent, and 83.3 percent of the stack diameter during each test run.

(ii) A valid test must consist of three Method 25A tests, each no less than 60 minutes in duration.

(iii) A 0–10 parts per million by volume-wet (ppmvw) (as propane) measurement range is preferred; as an alternative a 0–30 ppmvw (as carbon) measurement range may be used.

(iv) Calibration gases must be propane in air and be certified through EPA Protocol 1—''EPA Traceability Protocol for Assay and Certification of Gaseous Calibration Standards,'' September 1997, as amended August 25, 1999, EPA–600/R–97/121 (or more recent if updated since 1999).

(v) THC measurements must be reported in terms of ppmvw as propane.

(vi) THC results must be corrected to 3 percent CO_2, as measured by Method 3C of appendix A–2 of this part. You must use the following equation for this diluent concentration correction:

$$C_{corr} = C_{meas}\left(\frac{3}{CO_{2meas}}\right)$$

Where:

C_{meas} = The measured concentration of the pollutant.

CO_{2meas} = The measured concentration of the CO_2 diluent.

3 = The corrected reference concentration of CO_2 diluent.

C_{corr} = The corrected concentration of the pollutant.

(vii) Subtraction of methane or ethane from the THC data is not allowed in determining results.

(10) Visible emissions must be determined using Method 22 of appendix A–7 of this part. The test must be performed continuously during each test run. A digital color photograph of the exhaust point, taken from the position of the observer and annotated with date and time, must be taken once per test run and the 12 photos included in the test report specified in paragraph (d)(12) of this section.

(11) *Performance test criteria.* (i) The control device model tested must meet the criteria in paragraphs (d)(11)(i)(A) through (D) of this section. These criteria must be reported in the test report required by paragraph (d)(12) of this section.

(A) Results from Method 22 of appendix A–7 of this part determined under paragraph (d)(10) of this section with no indication of visible emissions.

(B) Average results from Method 25A of appendix A–7 of this part determined under paragraph (d)(9) of this section equal to or less than 10.0 ppmvw THC as propane corrected to 3.0 percent CO_2.

(C) Average CO emissions determined under paragraph (d)(8) of this section equal to or less than 10 parts ppmvd, corrected to 3.0 percent CO_2.

(D) Excess air determined under paragraph (d)(7) of this section equal to or greater than 150 percent.

(ii) The manufacturer must determine a maximum inlet gas flow rate which must not be exceeded for each control device model to achieve the criteria in paragraph (d)(11)(iii) of this section. The maximum inlet gas flow rate must be included in the test report required by paragraph (d)(12) of this section.

(iii) A control device meeting the criteria in paragraphs (d)(11)(i)(A) through (D) of this section must demonstrate a destruction efficiency of 95 percent for methane, if applicable, and VOC regulated under this subpart.

(12) The owner or operator of a combustion control device model tested under this paragraph must submit the information listed in paragraphs (d)(12)(i) through (vi) in the test report required by this section in accordance with § 60.5420a(b). Owners or operators who claim that any of the performance test information being submitted is confidential business information (CBI) must submit a complete file including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to Attn: CBI Officer; OAQPS CBIO Room 521; 109 T.W. Alexander Drive; RTP, NC 27711. The same file with the CBI omitted must be submitted to *Oil_and_Gas_PT@EPA.GOV.*

(i) A full schematic of the control device and dimensions of the device components.

(ii) The maximum net heating value of the device.

(iii) The test fuel gas flow range (in both mass and volume). Include the maximum allowable inlet gas flow rate.

(iv) The air/stream injection/assist ranges, if used.

(v) The test conditions listed in paragraphs (d)(12)(v)(A) through (O) of this section, as applicable for the tested model.

(A) Fuel gas delivery pressure and temperature.

(B) Fuel gas moisture range.

(C) Purge gas usage range.

(D) Condensate (liquid fuel) separation range.

(E) Combustion zone temperature range. This is required for all devices that measure this parameter.

(F) Excess air range.

(G) Flame arrestor(s).

(H) Burner manifold.

(I) Pilot flame indicator.

(J) Pilot flame design fuel and calculated or measured fuel usage.

(K) Tip velocity range.

(L) Momentum flux ratio.

(M) Exit temperature range.

(N) Exit flow rate.

(O) Wind velocity and direction.

(vi) The test report must include all calibration quality assurance/quality control data, calibration gas values, gas cylinder certification, strip charts, or other graphic presentations of the data annotated with test times and calibration values.

(e) *Continuous compliance for combustion control devices tested by the manufacturer in accordance with paragraph (d) of this section.* This paragraph applies to the demonstration of compliance for a combustion control device tested under the provisions in paragraph (d) of this section. Owners or operators must demonstrate that a control device achieves the performance criteria in paragraph (d)(11) of this section by installing a device tested under paragraph (d) of this section, complying with the criteria specified in paragraphs (e)(1) through (7) of this section, maintaining the records specified in 60.5420a(b) and submitting the reports specified in 60.5420a(c).

(1) The inlet gas flow rate must be equal to or less than the maximum specified by the manufacturer.

(2) A pilot flame must be present at all times of operation.

(3) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22 of appendix A–7 of this part must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(4) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(5) Following return to operation from maintenance or repair activity, each device must pass a visual observation according to EPA Method 22 of appendix A–7 of this part as described in paragraph (e)(3) of this section.

(6) If the owner or operator operates a combustion control device model tested under this section, an electronic copy of the performance test results required by this section shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

(7) Ensure that each enclosed combustion control device is maintained in a leak free condition.

§ 60.5415a How do I demonstrate continuous compliance with the standards for my well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, collection of fugitive emissions components at a well site, and collection of fugitive emissions components at a compressor station, and affected facilities at onshore natural gas processing plants?

(a) For each well affected facility, you must demonstrate continuous compliance by submitting the reports required by § 60.5420a(b) and maintaining the records for each completion operation specified in § 60.5420a(c)(1).

(b) For each centrifugal compressor affected facility and each pneumatic pump affected facility at a location with a control device on site, you must demonstrate continuous compliance according to paragraphs (b)(1) through (3) of this section.

(1) You must reduce methane and VOC emissions from the wet seal fluid degassing system and from the pneumatic pump by 95.0 percent or greater.

(2) For each control device used to reduce emissions, you must demonstrate continuous compliance with the performance requirements of § 60.5412a(a) using the procedures specified in paragraphs (b)(2)(i) through (vii) of this section. If you use a condenser as the control device to achieve the requirements specified in § 60.5412a(a)(2), you must demonstrate compliance according to paragraph (b)(2)(viii) of this section. You may switch between compliance with paragraphs (b)(2)(i) through (vii) of this section and compliance with paragraph (b)(2)(viii) of this section only after at least 1 year of operation in compliance with the selected approach. You must provide notification of such a change in the compliance method in the next annual report, as required in § 60.5420a(b), following the change.

(i) You must operate below (or above) the site specific maximum (or minimum) parameter value established according to the requirements of § 60.5417a(f)(1).

(ii) You must calculate the daily average of the applicable monitored parameter in accordance with § 60.5417a(e) except that the inlet gas flow rate to the control device must not be averaged.

(iii) Compliance with the operating parameter limit is achieved when the daily average of the monitoring parameter value calculated under paragraph (b)(2)(ii) of this section is either equal to or greater than the minimum monitoring value or equal to or less than the maximum monitoring value established under paragraph (b)(2)(i) of this section. When performance testing of a combustion control device is conducted by the device manufacturer as specified in § 60.5413a(d), compliance with the operating parameter limit is achieved when the criteria in § 60.5413a(e) are met.

(iv) You must operate the continuous monitoring system required in § 60.5417a at all times the affected source is operating, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments). A monitoring system malfunction is 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. You are required to complete monitoring system repairs in response to monitoring system malfunctions and to return the monitoring system to operation as expeditiously as practicable.

(v) You may not use data recorded during monitoring system malfunctions, repairs associated with monitoring system malfunctions, 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 required data collection periods to assess the operation of the control device and associated control system.

(vi) Failure to collect required data is a deviation of the monitoring requirements, except for periods of monitoring system malfunctions, repairs associated with monitoring system malfunctions, and required quality monitoring system quality assurance or quality control activities (including, as applicable, system accuracy audits and required zero and span adjustments).

(vii) If you use a combustion control device to meet the requirements of § 60.5412a(a) and you demonstrate compliance using the test procedures specified in § 60.5413a(b), you must comply with paragraphs (b)(2)(vii)(A) through (D) of this section.

(A) A pilot flame must be present at all times of operation.

(B) Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15-minute period. A visible emissions test conducted according to section 11 of EPA Method 22, 40 CFR part 60, appendix A, must be performed at least once every calendar month, separated by at least 15 days between each test. The observation period shall be 15 minutes.

(C) Devices failing the visible emissions test must follow manufacturer's repair instructions, if available, or best combustion engineering practice as outlined in the unit inspection and maintenance plan, to return the unit to compliant operation. All repairs and maintenance activities for each unit must be recorded in a maintenance and repair log and must be available for inspection.

(D) Following return to operation from maintenance or repair activity, each device must pass a Method 22 of appendix A–7 of this part visual observation as described in paragraph (b)(2)(vii)(B) of this section.

(viii) If you use a condenser as the control device to achieve the percent reduction performance requirements specified in § 60.5412a(a)(2), you must demonstrate compliance using the procedures in paragraphs (b)(2)(viii)(A) through (E) of this section.

(A) You must establish a site-specific condenser performance curve according to § 60.5417a(f)(2).

(B) You must calculate the daily average condenser outlet temperature in accordance with § 60.5417a(e).

(C) You must determine the condenser efficiency for the current operating day using the daily average condenser outlet temperature calculated under paragraph (b)(2)(viii)(B) of this section and the condenser performance curve established under paragraph (b)(2)(viii)(A) of this section.

(D) Except as provided in paragraphs (b)(2)(viii)(D)(*1*) and (*2*) of this section, at the end of each operating day, you must calculate the 365-day rolling average TOC emission reduction, as appropriate, from the condenser efficiencies as determined in paragraph (b)(2)(viii)(C) of this section.

(*1*) After the compliance dates specified in § 60.5370a, if you have less than 120 days of data for determining average TOC emission reduction, you must calculate the average TOC emission reduction for the first 120 days of operation after the compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the 120-day average TOC emission reduction is equal to or greater than 95.0 percent.

(*2*) After 120 days and no more than 364 days of operation after the compliance date specified in § 60.5370a, you must calculate the average TOC emission reduction as the TOC emission reduction averaged over the number of days between the current day and the applicable compliance date. You have demonstrated compliance with the overall 95.0 percent reduction requirement if the average TOC emission reduction is equal to or greater than 95.0 percent.

(E) If you have data for 365 days or more of operation, you have demonstrated compliance with the TOC emission reduction if the rolling 365-day average TOC emission reduction calculated in paragraph (b)(2)(viii)(D) of this section is equal to or greater than 95.0 percent.

(3) You must submit the annual report required by 60.5420a(b) and maintain the records as specified in

§ 60.5420a(c)(2), (6) through (11), and (16), as applicable.

(c) For each reciprocating compressor affected facility complying with § 60.5385a(a)(1) or (2), you must demonstrate continuous compliance according to paragraphs (c)(1) through (3) of this section. For each reciprocating compressor affected facility complying with § 60.5385a(a)(3), you must demonstrate continuous compliance according to paragraph (c)(4) of this section.

(1) You must continuously monitor the number of hours of operation for each reciprocating compressor affected facility or track the number of months since initial startup, or [date 60 days after publication of final rule in **Federal Register**], or the date of the most recent reciprocating compressor rod packing replacement, whichever is later.

(2) You must submit the annual report as required in § 60.5420a(b) and maintain records as required in § 60.5420a(c)(3).

(3) You must replace the reciprocating compressor rod packing before the total number of hours of operation reaches 26,000 hours or the number of months since the most recent rod packing replacement reaches 36 months.

(4) You must operate the rod packing emissions collection system under negative pressure and continuously comply with the closed vent requirements in § 60.5411a(a).

(d) For each pneumatic controller affected facility, you must demonstrate continuous compliance according to paragraphs (d)(1) through (3) of this section.

(1) You must continuously operate the pneumatic controllers as required in § 60.5390a(a), (b), or (c).

(2) You must submit the annual report as required in § 60.5420a(b).

(3) You must maintain records as required in § 60.5420a(c)(4).

(e) You must demonstrate continuous compliance according to paragraph (e)(3) of this section for each storage vessel affected facility, for which you are using a control device or routing emissions to a process to meet the requirement of § 60.5395a(a)(2).

(1)–(2) [Reserved]

(3) For each storage vessel affected facility, you must comply with paragraphs (e)(3)(i) and (ii) of this section.

(i) You must reduce methane and VOC emissions as specified in § 60.5395a(a).

(ii) For each control device installed to meet the requirements of § 60.5395a(a), you must demonstrate continuous compliance with the performance requirements of § 60.5412a(d) for each storage vessel affected facility using the procedure specified in paragraph (e)(3)(ii)(A) and either (e)(3)(ii)(B) or (e)(3)(ii)(C) of this section.

(A) You must comply with § 60.5416a(c) for each cover and closed vent system.

(B) You must comply with § 60.5417a(h) for each control device.

(C) Each closed vent system that routes emissions to a process must be operated as specified in § 60.5411a(c)(2).

(f) For affected facilities at onshore natural gas processing plants, continuous compliance with methane and VOC requirements is demonstrated if you are in compliance with the requirements of § 60.5400a.

(g) For each sweetening unit affected facility at onshore natural gas processing plants, you must demonstrate continuous compliance with the standards for SO_2 specified in § 60.5405a(b) according to paragraphs (g)(1) and (2) of this section.

(1) The minimum required SO_2 emission reduction efficiency (Z_c) is compared to the emission reduction efficiency (R) achieved by the sulfur recovery technology.

(i) If $R \geq Z_c$, your affected facility is in compliance.

(ii) If $R < Z_c$, your affected facility is not in compliance.

(2) The emission reduction efficiency (R) achieved by the sulfur reduction technology must be determined using the procedures in § 60.5406a(c)(1).

(h) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, you must demonstrate continuous compliance with the fugitive emission standards specified in § 60.5397a according to paragraphs (h)(1) through (4) of this section.

(1) You must conduct periodic monitoring surveys as required in § 60.5397a(f) through (i).

(2) You must repair or replace each identified source of fugitive emissions as required in § 60.5397a(j).

(3) You must maintain records as specified in § 60.5420a(c)(15).

(4) You must submit annual reports for collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5420a(b).

§ 60.5416a What are the initial and continuous cover and closed vent system inspection and monitoring requirements for my centrifugal compressor, reciprocating compressor, pneumatic pump and storage vessel affected facilities?

For each closed vent system or cover at your storage vessel, centrifugal compressor, reciprocating compressor and pneumatic pump affected facilities, you must comply with the applicable requirements of paragraphs (a) through (c) of this section.

(a) *Inspections for closed vent systems and covers installed on each centrifugal compressor, reciprocating compressor or pneumatic pump affected facility.* Except as provided in paragraphs (b)(11) and (12) of this section, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (a)(1) and (2) of this section, inspect each cover according to the procedures and schedule specified in paragraph (a)(3) of this section, and inspect each bypass device according to the procedures of paragraph (a)(4) of this section.

(1) For each closed vent system joint, seam, or other connection that is permanently or semi-permanently sealed (*e.g.,* a welded joint between two sections of hard piping or a bolted and gasketed ducting flange), you must meet the requirements specified in paragraphs (a)(1)(i) and (ii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must monitor a component or connection using the test methods and procedures in paragraph (b) of this section to demonstrate that it operates with no detectable emissions following any time the component is repaired or replaced or the connection is unsealed. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(2) For closed vent system components other than those specified in paragraph (a)(1) of this section, you must meet the requirements of paragraphs (a)(2)(i) through (iii) of this section.

(i) Conduct an initial inspection according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the closed vent system operates with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct annual inspections according to the test methods and procedures specified in paragraph (b) of this section to demonstrate that the components or connections operate with no detectable emissions. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(iii) Conduct annual visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in ductwork; loose connections; liquid leaks; or broken or missing caps or other closure devices. You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(3) For each cover, you must meet the requirements in paragraphs (a)(3)(i) and (ii) of this section.

(i) Conduct visual inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (e.g., fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(ii) You must initially conduct the inspections specified in paragraph (a)(3)(i) of this section following the installation of the cover. Thereafter, you must perform the inspection at least once every calendar year, except as provided in paragraphs (b)(11) and (12) of this section. You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(4) For each bypass device, except as provided for in § 60.5411a, you must meet the requirements of paragraphs (a)(4)(i) or (ii) of this section.

(i) Set the flow indicator to take a reading at least once every 15 minutes at the inlet to the bypass device that could divert the steam away from the control device to the atmosphere.

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections according to § 60.5420a(c)(8).

(b) *No detectable emissions test methods and procedures.* If you are required to conduct an inspection of a closed vent system or cover at your centrifugal compressor, reciprocating compressor, or pneumatic pump affected facility as specified in paragraphs (a)(1), (2), or (3) of this section, you must meet the requirements of paragraphs (b)(1) through (13) of this section.

(1) You must conduct the no detectable emissions test procedure in accordance with Method 21 of appendix A–7 of this part.

(2) The detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, except that the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the fluid and not for each individual organic compound in the stream.

(3) You must calibrate the detection instrument before use on each day of its use by the procedures specified in Method 21 of appendix A–7 of this part.

(4) Calibration gases must be as specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) Zero air (less than 10 parts per million by volume hydrocarbon in air).

(ii) A mixture of methane in air at a concentration less than 10,000 parts per million by volume.

(5) You may choose to adjust or not adjust the detection instrument readings to account for the background organic concentration level. If you choose to adjust the instrument readings for the background level, you must determine the background level value according to the procedures in Method 21 of appendix A–7 of this part.

(6) Your detection instrument must meet the performance criteria specified in paragraphs (b)(6)(i) and (ii) of this section.

(i) Except as provided in paragraph (b)(6)(ii) of this section, the detection instrument must meet the performance criteria of Method 21 of appendix A–7 of this part, except the instrument response factor criteria in section 8.1.1 of Method 21 must be for the average composition of the process fluid, not each individual volatile organic compound in the stream. For process streams that contain nitrogen, air, or other inerts that are not organic hazardous air pollutants or volatile organic compounds, you must calculate the average stream response factor on an inert-free basis.

(ii) If no instrument is available that will meet the performance criteria specified in paragraph (b)(6)(i) of this section, you may adjust the instrument readings by multiplying by the average response factor of the process fluid, calculated on an inert-free basis, as described in paragraph (b)(6)(i) of this section.

(7) You must determine if a potential leak interface operates with no detectable emissions using the applicable procedure specified in paragraph (b)(7)(i) or (ii) of this section.

(i) If you choose not to adjust the detection instrument readings for the background organic concentration level, then you must directly compare the maximum organic concentration value measured by the detection instrument to the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(ii) If you choose to adjust the detection instrument readings for the background organic concentration level, you must compare the value of the arithmetic difference between the maximum organic concentration value measured by the instrument and the background organic concentration value as determined in paragraph (b)(5) of this section with the applicable value for the potential leak interface as specified in paragraph (b)(8) of this section.

(8) A potential leak interface is determined to operate with no detectable organic emissions if the organic concentration value determined in paragraph (b)(7) of this section is less than 500 parts per million by volume.

(9) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (b)(9)(i) and (ii) of this section, except as provided in paragraph (b)(10) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 15 calendar days after the leak is detected.

(10) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(11) *Unsafe to inspect requirements.* You may designate any parts of the

closed vent system or cover as unsafe to inspect if the requirements in paragraphs (b)(11)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (a)(1), (2), or (3) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(12) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (b)(12)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (a)(1) through (3) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

(13) *Records.* Records shall be maintained as specified in this section and in § 60.5420a(c)(9).

(c) *Cover and closed vent system inspections for storage vessel affected facilities.* If you install a control device or route emissions to a process, you must inspect each closed vent system according to the procedures and schedule specified in paragraphs (c)(1) of this section, inspect each cover according to the procedures and schedule specified in paragraph (c)(2) of this section, and inspect each bypass device according to the procedures of paragraph (c)(3) of this section. You must also comply with the requirements of (c)(4) through (7) of this section.

(1) For each closed vent system, you must conduct an inspection at least once every calendar month as specified in paragraphs (c)(1)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(6).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in piping; loose connections; liquid leaks; or broken or missing caps or other closure devices.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(2) For each cover, you must conduct inspections at least once every calendar month as specified in paragraphs (c)(2)(i) through (iii) of this section.

(i) You must maintain records of the inspection results as specified in § 60.5420a(c)(7).

(ii) Conduct olfactory, visual and auditory inspections for defects that could result in air emissions. Defects include, but are not limited to, visible cracks, holes, or gaps in the cover, or between the cover and the separator wall; broken, cracked, or otherwise damaged seals or gaskets on closure devices; and broken or missing hatches, access covers, caps, or other closure devices. In the case where the storage vessel is buried partially or entirely underground, you must inspect only those portions of the cover that extend to or above the ground surface, and those connections that are on such portions of the cover (*e.g.,* fill ports, access hatches, gauge wells, etc.) and can be opened to the atmosphere.

(iii) Monthly inspections must be separated by at least 14 calendar days.

(3) For each bypass device, except as provided for in § 60.5411a(c)(3)(ii), you must meet the requirements of paragraphs (c)(3)(i) or (ii) of this section.

(i) You must properly install, calibrate and maintain a flow indicator at the inlet to the bypass device that could divert the stream away from the control device or process to the atmosphere. Set the flow indicator to trigger an audible and visible alarm, and initiate notification via remote alarm to the nearest field office, when the bypass device is open such that the stream is being, or could be, diverted away from the control device or process to the atmosphere. You must maintain records of each time the alarm is sounded according to § 60.5420a(c)(8).

(ii) If the bypass device valve installed at the inlet to the bypass device is secured in the non-diverting position using a car-seal or a lock-and-key type configuration, visually inspect the seal or closure mechanism at least once every month to verify that the valve is maintained in the non-diverting position and the vent stream is not diverted through the bypass device. You must maintain records of the inspections and records of each time the key is checked out, if applicable, according to § 60.5420a(c)(8).

(4) *Repairs.* In the event that a leak or defect is detected, you must repair the leak or defect as soon as practicable according to the requirements of paragraphs (c)(4)(i) through (iii) of this section, except as provided in paragraph (c)(5) of this section.

(i) A first attempt at repair must be made no later than 5 calendar days after the leak is detected.

(ii) Repair must be completed no later than 30 calendar days after the leak is detected.

(iii) Grease or another applicable substance must be applied to deteriorating or cracked gaskets to improve the seal while awaiting repair.

(5) *Delay of repair.* Delay of repair of a closed vent system or cover for which leaks or defects have been detected is allowed if the repair is technically infeasible without a shutdown, or if you determine that emissions resulting from immediate repair would be greater than the fugitive emissions likely to result from delay of repair. You must complete repair of such equipment by the end of the next shutdown.

(6) *Unsafe to inspect requirements.* You may designate any parts of the closed vent system or cover as unsafe to inspect if the requirements in paragraphs (c)(6)(i) and (ii) of this section are met. Unsafe to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment is unsafe to inspect because inspecting personnel would be exposed to an imminent or potential danger as a consequence of complying with paragraphs (c)(1) or (2) of this section.

(ii) You have a written plan that requires inspection of the equipment as frequently as practicable during safe-to-inspect times.

(7) *Difficult to inspect requirements.* You may designate any parts of the closed vent system or cover as difficult to inspect, if the requirements in paragraphs (c)(7)(i) and (ii) of this section are met. Difficult to inspect parts are exempt from the inspection requirements of paragraphs (c)(1) and (2) of this section.

(i) You determine that the equipment cannot be inspected without elevating the inspecting personnel more than 2 meters above a support surface.

(ii) You have a written plan that requires inspection of the equipment at least once every 5 years.

§ 60.5417a What are the continuous control device monitoring requirements for my centrifugal compressor, pneumatic pump, and storage vessel affected facilities?

You must meet the applicable requirements of this section to demonstrate continuous compliance for each control device used to meet emission standards for your storage vessel, centrifugal compressor or pneumatic pump affected facility.

(a) For each control device used to comply with the emission reduction standard for centrifugal compressor affected facilities in § 60.5380a(a)(1) or the emission reduction standard for pneumatic pumps affected facilities in § 60.5393a(b)(1), you must install and operate a continuous parameter monitoring system for each control device as specified in paragraphs (c) through (g) of this section, except as provided for in paragraph (b) of this section. If you install and operate a flare in accordance with § 60.5412a(a)(3), you are exempt from the requirements of paragraphs (e) and (f) of this section.

(b) You are exempt from the monitoring requirements specified in paragraphs (c) through (g) of this section for the control devices listed in paragraphs (b)(1) and (2) of this section.

(1) A boiler or process heater in which all vent streams are introduced with the primary fuel or are used as the primary fuel.

(2) A boiler or process heater with a design heat input capacity equal to or greater than 44 megawatts.

(c) If you are required to install a continuous parameter monitoring system, you must meet the specifications and requirements in paragraphs (c)(1) through (4) of this section.

(1) Each continuous parameter monitoring system must measure data values at least once every hour and record the parameters in paragraphs (c)(1)(i) or (ii) of this section.

(i) Each measured data value.

(ii) Each block average value for each 1-hour period or shorter periods calculated from all measured data values during each period. If values are measured more frequently than once per minute, a single value for each minute may be used to calculate the hourly (or shorter period) block average instead of all measured values.

(2) You must prepare a site-specific monitoring plan that addresses the monitoring system design, data collection, and the quality assurance and quality control elements outlined in paragraphs (c)(2)(i) through (v) of this section. You must install, calibrate, operate, and maintain each continuous parameter monitoring system in accordance with the procedures in your approved site-specific monitoring plan.

(i) The performance criteria and design specifications for the monitoring system equipment, including the sample interface, detector signal analyzer, and data acquisition and calculations.

(ii) Sampling interface (*e.g.*, thermocouple) location such that the monitoring system will provide representative measurements.

(iii) Equipment performance checks, system accuracy audits, or other audit procedures.

(iv) Ongoing operation and maintenance procedures in accordance with provisions in § 60.13(b).

(v) Ongoing reporting and recordkeeping procedures in accordance with provisions in § 60.7(c), (d), and (f).

(3) You must conduct the continuous parameter monitoring system equipment performance checks, system accuracy audits, or other audit procedures specified in the site-specific monitoring plan at least once every 12 months.

(4) You must conduct a performance evaluation of each continuous parameter monitoring system in accordance with the site-specific monitoring plan.

(d) You must install, calibrate, operate, and maintain a device equipped with a continuous recorder to measure the values of operating parameters appropriate for the control device as specified in paragraph (d)(1), (2), or (3) of this section.

(1) A continuous monitoring system that measures the operating parameters in paragraphs (d)(1)(i) through (viii) of this section, as applicable.

(i) For a thermal vapor incinerator that demonstrates during the performance test conducted under § 60.5413a that combustion zone temperature is an accurate indicator of performance, a temperature monitoring device equipped with a continuous recorder. The monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(ii) For a catalytic vapor incinerator, a temperature monitoring device equipped with a continuous recorder. The device must be capable of monitoring temperature at two locations and have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install one temperature sensor in the vent stream at the nearest feasible point to the catalyst bed inlet, and you must install a second temperature sensor in the vent stream at the nearest feasible point to the catalyst bed outlet.

(iii) For a flare, a heat sensing monitoring device equipped with a continuous recorder that indicates the continuous ignition of the pilot flame.

(iv) For a boiler or process heater, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location representative of the combustion zone temperature.

(v) For a condenser, a temperature monitoring device equipped with a continuous recorder. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater. You must install the temperature sensor at a location in the exhaust vent stream from the condenser.

(vi) For a regenerative-type carbon adsorption system, a continuous monitoring system that meets the specifications in paragraphs (d)(1)(vi)(A) and (B) of this section.

(A) The continuous parameter monitoring system must measure and record the average total regeneration stream mass flow or volumetric flow during each carbon bed regeneration cycle. The flow sensor must have a measurement sensitivity of 5 percent of the flow rate or 10 cubic feet per minute, whichever is greater. You must check the mechanical connections for leakage at least every month, and you must perform a visual inspection at least every 3 months of all components of the flow continuous parameter monitoring system for physical and operational integrity and all electrical connections for oxidation and galvanic corrosion if your flow continuous parameter monitoring system is not equipped with a redundant flow sensor; and

(B) The continuous parameter monitoring system must measure and record the average carbon bed temperature for the duration of the carbon bed steaming cycle and measure the actual carbon bed temperature after regeneration and within 15 minutes of completing the cooling cycle. The temperature monitoring device must have a minimum accuracy of ±1 percent of the temperature being monitored in °C, or ±2.5 °C, whichever value is greater.

(vii) For a nonregenerative-type carbon adsorption system, you must monitor the design carbon replacement interval established using a design analysis performed as specified in § 60.5413a(c)(3). The design carbon replacement interval must be based on the total carbon working capacity of the control device and source operating schedule.

(viii) For a combustion control device whose model is tested under § 60.5413a(d), a continuous monitoring system meeting the requirements of paragraphs (d)(1)(viii)(A) and (B) of this section.

(A) The continuous monitoring system must measure gas flow rate at the inlet to the control device. The monitoring instrument must have an accuracy of ±2 percent or better. The flow rate at the inlet to the combustion device must not exceed the maximum or be less than the minimum flow rate determined by the manufacturer.

(B) A monitoring device that continuously indicates the presence of the pilot flame while emissions are routed to the control device.

(2) An organic monitoring device equipped with a continuous recorder that measures the concentration level of organic compounds in the exhaust vent stream from the control device. The monitor must meet the requirements of Performance Specification 8 or 9 of appendix B of this part. You must install, calibrate, and maintain the monitor according to the manufacturer's specifications.

(3) A continuous monitoring system that measures operating parameters other than those specified in paragraph (d)(1) or (2) of this section, upon approval of the Administrator as specified in § 60.13(i).

(e) You must calculate the daily average value for each monitored operating parameter for each operating day, using the data recorded by the monitoring system, except for inlet gas flow rate. If the emissions unit operation is continuous, the operating day is a 24-hour period. If the emissions unit operation is not continuous, the operating day is the total number of hours of control device operation per 24-hour period. Valid data points must be available for 75 percent of the operating hours in an operating day to compute the daily average.

(f) For each operating parameter monitor installed in accordance with the requirements of paragraph (d) of this section, you must comply with paragraph (f)(1) of this section for all control devices. When condensers are installed, you must also comply with paragraph (f)(2) of this section.

(1) You must establish a minimum operating parameter value or a maximum operating parameter value, as appropriate for the control device, to define the conditions at which the control device must be operated to continuously achieve the applicable performance requirements of § 60.5412a(a). You must establish each minimum or maximum operating parameter value as specified in paragraphs (f)(1)(i) through (iii) of this section.

(i) If you conduct performance tests in accordance with the requirements of § 60.5413a(b) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on values measured during the performance test and supplemented, as necessary, by a condenser design analysis or control device manufacturer recommendations or a combination of both.

(ii) If you use a condenser design analysis in accordance with the requirements of § 60.5413a(c) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then you must establish the minimum operating parameter value or the maximum operating parameter value based on the condenser design analysis and supplemented, as necessary, by the condenser manufacturer's recommendations.

(iii) If you operate a control device where the performance test requirement was met under § 60.5413a(d) to demonstrate that the control device achieves the applicable performance requirements specified in § 60.5412a(a), then your control device inlet gas flow rate must not exceed the maximum or be less than the minimum inlet gas flow rate determined by the manufacturer.

(2) If you use a condenser as specified in paragraph (d)(1)(v) of this section, you must establish a condenser performance curve showing the relationship between condenser outlet temperature and condenser control efficiency, according to the requirements of paragraphs (f)(2)(i) and (ii) of this section.

(i) If you conduct a performance test in accordance with the requirements of § 60.5413a(b) to demonstrate that the condenser achieves the applicable performance requirements in § 60.5412a(a), then the condenser performance curve must be based on values measured during the performance test and supplemented as necessary by control device design analysis, or control device manufacturer's recommendations, or a combination or both.

(ii) If you use a control device design analysis in accordance with the requirements of § 60.5413a(c)(1) to demonstrate that the condenser achieves the applicable performance requirements specified in § 60.5412a(a), then the condenser performance curve must be based on the condenser design analysis and supplemented, as necessary, by the control device manufacturer's recommendations.

(g) A deviation for a given control device is determined to have occurred when the monitoring data or lack of monitoring data result in any one of the criteria specified in paragraphs (g)(1) through (g)(6) of this section being met. If you monitor multiple operating parameters for the same control device during the same operating day and more than one of these operating parameters meets a deviation criterion specified in paragraphs (g)(1) through (6) of this section, then a single excursion is determined to have occurred for the control device for that operating day.

(1) A deviation occurs when the daily average value of a monitored operating parameter is less than the minimum operating parameter limit (or, if applicable, greater than the maximum operating parameter limit) established in paragraph (f)(1) of this section.

(2) If you are subject to § 60.5412a(a)(2), a deviation occurs when the 365-day average condenser efficiency calculated according to the requirements specified in § 60.5415a(b)(2)(viii)(D) is less than 95.0 percent.

(3) If you are subject to § 60.5412a(a)(2) and you have less than 365 days of data, a deviation occurs when the average condenser efficiency calculated according to the procedures specified in § 60.5415a(b)(2)(viii)(D)(*1*) or (*2*) is less than 95.0 percent.

(4) A deviation occurs when the monitoring data are not available for at least 75 percent of the operating hours in a day.

(5) If the closed vent system contains one or more bypass devices that could be used to divert all or a portion of the gases, vapors, or fumes from entering the control device, a deviation occurs when the requirements of paragraph (g)(5)(i) or (ii) of this section are met.

(i) For each bypass line subject to § 60.5411a(a)(3)(i)(A), the flow indicator indicates that flow has been detected and that the stream has been diverted away from the control device to the atmosphere.

(ii) For each bypass line subject to § 60.5411a(a)(3)(i)(B), if the seal or closure mechanism has been broken, the bypass line valve position has changed, the key for the lock-and-key type lock has been checked out, or the car-seal has broken.

(6) For a combustion control device whose model is tested under § 60.5413a(d), a deviation occurs when the conditions of paragraphs (g)(6)(i) or (ii) are met.

(i) The inlet gas flow rate exceeds the maximum established during the test conducted under § 60.5413a(d).

(ii) Failure of the monthly visible emissions test conducted under § 60.5413a(e)(3) occurs.

(h) For each control device used to comply with the emission reduction standard in § 60.5395a(a)(2) for your storage vessel affected facility, you must demonstrate continuous compliance according to paragraphs (h)(1) through (h)(4) of this section. You are exempt from the requirements of this paragraph if you install a control device model tested in accordance with § 60.5413a(d)(2) through (10), which meets the criteria in § 60.5413a(d)(11), the reporting requirement in § 60.5413a(d)(12), and meet the continuous compliance requirement in § 60.5413a(e).

(1) For each combustion device you must conduct inspections at least once every calendar month according to paragraphs (h)(1)(i) through (iv) of this section. Monthly inspections must be separated by at least 14 calendar days.

(i) Conduct visual inspections to confirm that the pilot is lit when vapors are being routed to the combustion device and that the continuous burning pilot flame is operating properly.

(ii) Conduct inspections to monitor for visible emissions from the combustion device using section 11 of EPA Method 22 of appendix A of this part. The observation period shall be 15 minutes. Devices must be operated with no visible emissions, except for periods not to exceed a total of 1 minute during any 15 minute period.

(iii) Conduct olfactory, visual and auditory inspections of all equipment associated with the combustion device to ensure system integrity.

(iv) For any absence of the pilot flame, or other indication of smoking or improper equipment operation (*e.g.,* visual, audible, or olfactory), you must ensure the equipment is returned to proper operation as soon as practicable after the event occurs. At a minimum, you must perform the procedures specified in paragraphs (h)(1)(iv)(A) and (B) of this section.

(A) You must check the air vent for obstruction. If an obstruction is observed, you must clear the obstruction as soon as practicable.

(B) You must check for liquid reaching the combustor.

(2) For each vapor recovery device, you must conduct inspections at least once every calendar month to ensure physical integrity of the control device according to the manufacturer's instructions. Monthly inspections must be separated by at least 14 calendar days.

(3) Each control device must be operated following the manufacturer's written operating instructions, procedures and maintenance schedule to ensure good air pollution control practices for minimizing emissions. Records of the manufacturer's written operating instructions, procedures, and maintenance schedule must be available for inspection as specified in § 60.5420a(c)(13).

(4) Conduct a periodic performance test no later than 60 months after the initial performance test as specified in § 60.5413a(b)(5)(ii) and conduct subsequent periodic performance tests at intervals no longer than 60 months following the previous periodic performance test.

§ 60.5420a What are my notification, reporting, and recordkeeping requirements?

(a) You must submit the notifications according to paragraphs (a)(1) and (2) of this section if you own or operate one or more of the affected facilities specified in § 60.5365a that was constructed, modified, or reconstructed during the reporting period.

(1) If you own or operate a well, centrifugal compressor, reciprocating compressor, pneumatic controller, pneumatic pump, storage vessel, or collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station you are not required to submit the notifications required in § 60.7(a)(1), (3), and (4).

(2)(i) If you own or operate a well affected facility, you must submit a notification to the Administrator no later than 2 days prior to the commencement of each well completion operation listing the anticipated date of the well completion operation. The notification shall include contact information for the owner or operator; the API well number; the latitude and longitude coordinates for each well in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983; and the planned date of the beginning of flowback. You may submit the notification in writing or in electronic format.

(ii) If you are subject to state regulations that require advance notification of well completions and you have met those notification requirements, then you are considered to have met the advance notification requirements of paragraph (a)(2)(i) of this section.

(b) *Reporting requirements.* You must submit annual reports containing the information specified in paragraphs (b)(1) through (8) of this section and performance test reports as specified in paragraph (b)(9) or (10) of this section. You must submit annual reports following the procedure specified in paragraph (b)(11). The initial annual report is due no later than 90 days after the end of the initial compliance period as determined according to § 60.5410a. Subsequent annual reports are due no later than same date each year as the initial annual report. If you own or operate more than one affected facility, you may submit one report for multiple affected facilities provided the report contains all of the information required as specified in paragraphs (b)(1) through (10) of this section. Annual reports may coincide with title V reports as long as all the required elements of the annual report are included. You may arrange with the Administrator a common schedule on which reports required by this part may be submitted as long as the schedule does not extend the reporting period.

(1) The general information specified in paragraphs (b)(1)(i) through (iv) of this section for all reports.

(i) The company name and address of the affected facility.

(ii) An identification of each affected facility being included in the annual report.

(iii) Beginning and ending dates of the reporting period.

(iv) A certification by a certifying official of truth, accuracy, and completeness. This certification shall state that, based on information and belief formed after reasonable inquiry, the statements and information in the document are true, accurate, and complete.

(2) For each well affected facility, the information in paragraphs (b)(2)(i) and (ii) of this section.

(i) Records of each well completion operation as specified in paragraph (c)(1)(i) through (iv) of this section for each well affected facility conducted during the reporting period. In lieu of submitting the records specified in paragraph (c)(1)(i) through (iv), the owner or operator may submit a list of the well completions with hydraulic fracturing completed during the reporting period and the records required by paragraph (c)(1)(v) of this section for each well completion.

(ii) Records of deviations specified in paragraph (c)(1)(ii) of this section that occurred during the reporting period.

(3) For each centrifugal compressor affected facility, the information

specified in paragraphs (b)(3)(i) through (iv) of this section.

(i) An identification of each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(ii) Records of deviations specified in paragraph (c)(2) of this section that occurred during the reporting period.

(iii) If required to comply with § 60.5380a(a)(2), the records specified in paragraphs (c)(6) through (11) of this section.

(iv) If complying with § 60.5380a(a)(1) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraph (c)(2)(i) through (c)(2)(vii) of this section for each centrifugal compressor using a wet seal system constructed, modified or reconstructed during the reporting period.

(4) For each reciprocating compressor affected facility, the information specified in paragraphs (b)(4)(i) and (ii) of this section.

(i) The cumulative number of hours of operation or the number of months since initial startup, since [date 60 days after publication of final rule in the **Federal Register**], or since the previous reciprocating compressor rod packing replacement, whichever is later.

(ii) Records of deviations specified in paragraph (c)(3)(iii) of this section that occurred during the reporting period.

(5) For each pneumatic controller affected facility, the information specified in paragraphs (b)(5)(i) through (iii) of this section.

(i) An identification of each pneumatic controller constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5390a(b)(2) or (c)(2).

(ii) If applicable, documentation that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than 6 standard cubic feet per hour are required and the reasons why.

(iii) Records of deviations specified in paragraph (c)(4)(v) of this section that occurred during the reporting period.

(6) For each storage vessel affected facility, the information in paragraphs (b)(6)(i) through (vii) of this section.

(i) An identification, including the location, of each storage vessel affected facility for which construction, modification or reconstruction commenced during the reporting period. The location of the storage vessel shall be in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(ii) Documentation of the VOC emission rate determination according to § 60.5365a(e) for each storage vessel that became an affected facility during the reporting period or is returned to service during the reporting period.

(iii) Records of deviations specified in paragraph (c)(5)(iii) of this section that occurred during the reporting period.

(iv) A statement that you have met the requirements specified in § 60.5410a(h)(2) and (3).

(v) You must identify each storage vessel affected facility that is removed from service during the reporting period as specified in § 60.5395a(c)(1)(ii), including the date the storage vessel affected facility was removed from service.

(vi) You must identify each storage vessel affected facility returned to service during the reporting period as specified in § 60.5395a(c)(3), including the date the storage vessel affected facility was returned to service.

(vii) If complying with § 60.5395a(a)(2) with a control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e), records specified in paragraphs (c)(5)(vi)(A) through (G) of this section for each storage vessel constructed, modified, reconstructed or returned to service during the reporting period.

(7) For the collection of fugitive emissions components at a well site and the collection of fugitive emissions components at a compressor station, the records of each monitoring survey conducted during the year:

(i) Date of the survey.

(ii) Beginning and end time of the survey.

(iii) Name of operator(s) performing survey. If the survey is performed by optical gas imaging, you must note the training and experience of the operator.

(iv) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(v) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(vi) Documentation of each fugitive emission, including the information specified in paragraphs (b)(7)(vi)(A) through (C) of this section

(A) Location.

(B) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(C) The date of successful repair of the fugitive emissions component.

(D) Type of instrument used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(8) For each pneumatic pump affected facility, the information specified in paragraphs (b)(8)(i) through (v) of this section.

(i) In the initial annual report, a certification that there is no control device on site, if applicable.

(ii) An identification of each pneumatic pump constructed, modified or reconstructed during the reporting period, including the identification information specified in § 60.5393a(a)(2) or (b)(2).

(iii) An identification of any sites which contain natural pneumatic pumps and which installed a control device during the reporting period, where there was no control device previously at the site.

(iv) Records of deviations specified in paragraph (c)(16)(ii) of this section that occurred during the reporting period.

(v) If complying with § 60.5393a(b)(1) with a control device tested under § 60.5413(d), which meets the criteria in § 60.5413(d)(11) and § 60.5413(e), records specified in paragraphs (c)(16)(iv)(A) through (G) of this section for each pneumatic pump constructed, modified or reconstructed during the reporting period.

(9) Within 60 days after the date of completing each performance test (see § 60.8) required by this subpart, except testing conducted by the manufacturer as specified in § 60.5413a(d), you must submit the results of the performance test following the procedure specified in either paragraph (b)(9)(i) or (ii) of this section.

(i) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*) at the time of the test, you must submit the results of the performance test to the EPA via the

Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Performance test data must be submitted in a file format generated through the use of the EPA's ERT or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAQPS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(ii) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site at the time of the test, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 60.4.

(10) For combustion control devices tested by the manufacturer in accordance with § 60.5413a(d), an electronic copy of the performance test results required by § 60.5413a(d) shall be submitted via email to *Oil_and_Gas_PT@EPA.GOV* unless the test results for that model of combustion control device are posted at the following Web site: *epa.gov/airquality/oilandgas/.*

(11) You must submit reports to the EPA via the CEDRI. (CEDRI can be accessed through the EPA's CDX (*https://cdx.epa.gov/).*) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The reports must be submitted by the deadlines specified in this subpart, regardless of the method in which the reports are submitted.

(c) *Recordkeeping requirements.* You must maintain the records identified as specified in § 60.7(f) and in paragraphs (c)(1) through (16) of this section. All records required by this subpart must be maintained either onsite or at the nearest local field office for at least 5 years. Any records required to be maintained by this subpart that are submitted electronically via the EPA's CDX may be maintained in electronic format.

(1) The records for each well affected facility as specified in paragraphs (c)(1)(i) through (v) of this section.

(i) Records identifying each well completion operation for each well affected facility;

(ii) Records of deviations in cases where well completion operations with hydraulic fracturing were not performed in compliance with the requirements specified in § 60.5375a.

(iii) Records required in § 60.5375a(b) or (f) for each well completion operation conducted for each well affected facility that occurred during the reporting period. You must maintain the records specified in paragraphs (c)(1)(iii)(A) and (B) of this section.

(A) For each well affected facility required to comply with the requirements of § 60.5375a(a), you must record: The location of the well; the API well number; the date and time of the onset of flowback following hydraulic fracturing or refracturing; the date and time of each attempt to direct flowback to a separator as required in § 60.5375a(a)(1)(ii); the date and time of each occurrence of returning to the initial flowback stage under § 60.5375a(a)(1)(i); and the date and time that the well was shut in and the flowback equipment was permanently disconnected, or the startup of production; the duration of flowback; duration of recovery to the flow line; duration of combustion; duration of venting; and specific reasons for venting in lieu of capture or combustion. The duration must be specified in hours.

(B) For each well affected facility required to comply with the requirements of § 60.5375a(f), you must maintain the records specified in paragraph (c)(1)(iii)(A) of this section except that you do not have to record the duration of recovery to the flow line.

(iv) For each well affected facility for which you claim an exception under § 60.5375a(a)(3), you must record: The location of the well; the API well number; the specific exception claimed; the starting date and ending date for the period the well operated under the exception; and an explanation of why the well meets the claimed exception.

(v) For each well affected facility required to comply with both § 60.5375a(a)(1) and (3), if you are using a digital photograph in lieu of the records required in paragraphs (c)(1)(i) through (iv) of this section, you must retain the records of the digital photograph as specified in § 60.5410a(a)(4).

(2) For each centrifugal compressor affected facility, you must maintain records of deviations in cases where the centrifugal compressor was not operated in compliance with the requirements specified in § 60.5380a. Except as specified in paragraph (c)(2)(vii) of this section, you must maintain the records in paragraphs (c)(2)(i) through (vi) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5380a(a)(1) for each centrifugal compressor.

(i) Make, model and serial number of purchased device.

(ii) Date of purchase.

(iii) Copy of purchase order.

(iv) Location of the centrifugal compressor and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(v) Inlet gas flow rate.

(vi) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(2)(vi)(A) through (D) of this section.

(A) Records that the pilot flame is present at all times of operation.

(B) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(C) Records of the maintenance and repair log.

(D) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(vii) As an alternative to the requirements of paragraph (c)(2)(iv) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the centrifugal compressor and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the centrifugal compressor and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(3) For each reciprocating compressor affected facility, you must maintain the records in paragraphs (c)(3)(i) through (iii) of this section.

(i) Records of the cumulative number of hours of operation or number of months since initial startup or [date 60 days after publication of final rule in the **Federal Register**], or the previous replacement of the reciprocating compressor rod packing, whichever is later.

(ii) Records of the date and time of each reciprocating compressor rod packing replacement, or date of installation of a rod packing emissions collection system and closed vent system as specified in § 60.5385a(a)(3).

(iii) Records of deviations in cases where the reciprocating compressor was not operated in compliance with the requirements specified in § 60.5385a.

(4) For each pneumatic controller affected facility, you must maintain the records identified in paragraphs (c)(4)(i) through (v) of this section, as applicable.

(i) Records of the date, location and manufacturer specifications for each pneumatic controller constructed, modified or reconstructed.

(ii) Records of the demonstration that the use of pneumatic controller affected facilities with a natural gas bleed rate greater than the applicable standard are required and the reasons why.

(iii) If the pneumatic controller is not located at a natural gas processing plant, records of the manufacturer's specifications indicating that the controller is designed such that natural gas bleed rate is less than or equal to 6 standard cubic feet per hour.

(iv) If the pneumatic controller is located at a natural gas processing plant, records of the documentation that the natural gas bleed rate is zero.

(v) Records of deviations in cases where the pneumatic controller was not operated in compliance with the requirements specified in § 60.5390a.

(5) For each storage vessel affected facility, you must maintain the records identified in paragraphs (c)(5)(i) through (vi) of this section.

(i) If required to reduce emissions by complying with § 60.5395a(a)(2), the records specified in §§ 60.5420a(c)(6) through (8), 60.5416a(c)(6)(ii), and 60.5416a(c)(7)(ii). You must maintain the records in paragraph (c)(5)(vi) of this part for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(ii) Records of each VOC emissions determination for each storage vessel affected facility made under § 60.5365a(e) including identification of the model or calculation methodology used to calculate the VOC emission rate.

(iii) Records of deviations in cases where the storage vessel was not operated in compliance with the requirements specified in §§ 60.5395a, 60.5411a, 60.5412a, and 60.5413a, as applicable.

(iv) For storage vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), records indicating the number of consecutive days that the vessel is located at a site in the oil and natural gas production segment, natural gas processing segment or natural gas transmission and storage segment. If a storage vessel is removed from a site and, within 30 days, is either returned to the site or replaced by another storage vessel at the site to serve the same or similar function, then the entire period since the original storage vessel was first located at the site, including the days when the storage vessel was removed, will be added to the count towards the number of consecutive days.

(v) You must maintain records of the identification and location of each storage vessel affected facility.

(vi) Except as specified in paragraph (c)(5)(vi)(G) of this section, you must maintain the records specified in paragraphs (c)(5)(vi)(A) through (F) of this section for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5395a(a)(2) for each storage vessel.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(5)(vi)(F)(*1*) through (*4*).

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(G) As an alternative to the requirements of paragraph (c)(5)(vi)(D) of this section, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the storage vessel and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the storage vessel and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(6) Records of each closed vent system inspection required under § 60.5416a(a)(1) and (a)(2) for centrifugal compressors, reciprocating compressors and pneumatic pumps, or § 60.5416a(c)(1) for storage vessels.

(7) A record of each cover inspection required under § 60.5416a(a)(3) for centrifugal or reciprocating compressors or § 60.5416a(c)(2) for storage vessels.

(8) If you are subject to the bypass requirements of § 60.5416a(a)(4) for centrifugal compressors, reciprocating compressors or pneumatic pumps, or § 60.5416a(c)(3) for storage vessels, a record of each inspection or a record of each time the key is checked out or a record of each time the alarm is sounded.

(9) If you are subject to the closed vent system no detectable emissions requirements of § 60.5416a(b) for centrifugal compressors, reciprocating compressors or pneumatic pumps, a record of the monitoring conducted in accordance with § 60.5416a(b).

(10) For each centrifugal compressor or pneumatic pump affected facility, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5413a(c)(2) or (3)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(11) For each centrifugal compressor or pneumatic pump affected facility subject to the control device requirements of § 60.5412a(a), (b), and (c), records of minimum and maximum operating parameter values, continuous parameter monitoring system data, calculated averages of continuous parameter monitoring system data, results of all compliance calculations, and results of all inspections.

(12) For each carbon adsorber installed on storage vessel affected

facilities, records of the schedule for carbon replacement (as determined by the design analysis requirements of § 60.5412a(d)(2)) and records of each carbon replacement as specified in § 60.5412a(c)(1).

(13) For each storage vessel affected facility subject to the control device requirements of § 60.5412a(c) and (d), you must maintain records of the inspections, including any corrective actions taken, the manufacturers' operating instructions, procedures and maintenance schedule as specified in § 60.5417a(h)(3). You must maintain records of EPA Method 22 of appendix A–7 of this part, section 11 results, which include: Company, location, company representative (name of the person performing the observation), sky conditions, process unit (type of control device), clock start time, observation period duration (in minutes and seconds), accumulated emission time (in minutes and seconds), and clock end time. You may create your own form including the above information or use Figure 22–1 in EPA Method 22 of appendix A–7 of this part. Manufacturer's operating instructions, procedures and maintenance schedule must be available for inspection.

(14) A log of records as specified in §§ 60.5412a(d)(1)(iii), for all inspection, repair and maintenance activities for each control device failing the visible emissions test.

(15) For each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station, the records identified in paragraphs (c)(15)(i) and (ii) of this section.

(i) The fugitive emissions monitoring plan for each collection of fugitive emissions components at a well site and each collection of fugitive emissions components at a compressor station as required in § 60.5397a(a).

(ii) The records of each monitoring survey as specified in paragraphs (c)(15)(ii)(A) through (F) of this section.

(A) Date of the survey.

(B) Beginning and end time of the survey.

(C) Name of operator(s) performing survey. You must note the training and experience of the operator.

(D) Ambient temperature, sky conditions, and maximum wind speed at the time of the survey.

(E) Any deviations from the monitoring plan or a statement that there were no deviations from the monitoring plan.

(F) Documentation of each fugitive emission, including the information specified in paragraphs (c)(15)(ii)(F)(*1*) through (*2*) of this section.

(*1*) Location.

(*2*) One or more digital photographs of each required monitoring survey being performed. The digital photograph must include the date the photograph was taken and the latitude and longitude of the collection of fugitive emissions components at a well site or collection of fugitive emissions components at a compressor station imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the monitoring survey being performed with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

(3) The date of successful repair of the fugitive emissions component.

(4) Instrumentation used to resurvey a repaired fugitive emissions component that could not be repaired during the initial fugitive emissions finding.

(16) For each pneumatic pump affected facility, you must maintain the records identified in paragraphs (c)(16)(i) through (iv) of this section.

(i) Records of the date, location and manufacturer specifications for each pneumatic pump constructed, modified or reconstructed.

(ii) Records of deviations in cases where the pneumatic pump was not operated in compliance with the requirements specified in § 60.5393a.

(iii) Records of the control device installation date and the location of sites containing pneumatic pumps at which a control device was installed, where previously there was no control device at the site.

(iv) Except as specified in paragraph (c)(16)(iv)(G) of this section, records for each control device tested under § 60.5413a(d) which meets the criteria in § 60.5413a(d)(11) and § 60.5413a(e) and used to comply with § 60.5393a(b)(1) for each pneumatic pump.

(A) Make, model and serial number of purchased device.

(B) Date of purchase.

(C) Copy of purchase order.

(D) Location of the pneumatic pump and control device in latitude and longitude coordinates in decimal degrees to an accuracy and precision of five (5) decimals of a degree using the North American Datum of 1983.

(E) Inlet gas flow rate.

(F) Records of continuous compliance requirements in § 60.5413a(e) as specified in paragraphs (c)(16)(iv)(F)(*1*) through (*4*) of this section.

(*1*) Records that the pilot flame is present at all times of operation.

(*2*) Records that the device was operated with no visible emissions except for periods not to exceed a total of 2 minutes during any hour.

(*3*) Records of the maintenance and repair log.

(*4*) Records of the visible emissions test following return to operation from a maintenance or repair activity.

(G) As an alternative to the requirements of paragraph (c)(16)(iv)(D) of this part, you may maintain records of one or more digital photographs with the date the photograph was taken and the latitude and longitude of the pneumatic pump and control device imbedded within or stored with the digital file. As an alternative to imbedded latitude and longitude within the digital photograph, the digital photograph may consist of a photograph of the pneumatic pump and control device with a photograph of a separately operating GIS device within the same digital picture, provided the latitude and longitude output of the GIS unit can be clearly read in the digital photograph.

§ 60.5421a What are my additional recordkeeping requirements for my affected facility subject to methane and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraph (b) of this section in addition to the requirements of § 60.486a.

(b) The following recordkeeping requirements apply to pressure relief devices subject to the requirements of § 60.5401a(b)(1) of this subpart.

(1) When each leak is detected as specified in § 60.5401a(b)(2), a weatherproof and readily visible identification, marked with the equipment identification number, must be attached to the leaking equipment. The identification on the pressure relief device may be removed after it has been repaired.

(2) When each leak is detected as specified in § 60.5401a(b)(2), the information specified in paragraphs (b)(2)(i) through (x) of this section must be recorded in a log and shall be kept for 2 years in a readily accessible location:

(i) The instrument and operator identification numbers and the equipment identification number.

(ii) The date the leak was detected and the dates of each attempt to repair the leak.

(iii) Repair methods applied in each attempt to repair the leak.

(iv) ''Above 500 ppm'' if the maximum instrument reading measured by the methods specified in § 60.5400a(d) after each repair attempt is 500 ppm or greater.

(v) ''Repair delayed'' and the reason for the delay if a leak is not repaired within 15 calendar days after discovery of the leak.

(vi) The signature of the owner or operator (or designate) whose decision it was that repair could not be effected without a process shutdown.

(vii) The expected date of successful repair of the leak if a leak is not repaired within 15 days.

(viii) Dates of process unit shutdowns that occur while the equipment is unrepaired.

(ix) The date of successful repair of the leak.

(x) A list of identification numbers for equipment that are designated for no detectable emissions under the provisions of § 60.482–4a(a). The designation of equipment subject to the provisions of § 60.482–4a(a) must be signed by the owner or operator.

§ 60.5422a What are my additional reporting requirements for my affected facility subject to methane and VOC requirements for onshore natural gas processing plants?

(a) You must comply with the requirements of paragraphs (b) and (c) of this section in addition to the requirements of § 60.487a(a), (b), (c)(2)(i) through (iv), and (c)(2)(vii) through (viii). You must submit semiannual reports to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) Use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted.

(b) An owner or operator must include the following information in the initial semiannual report in addition to the information required in § 60.487a(b)(1) through (4): Number of pressure relief devices subject to the requirements of § 60.5401a(b) except for those pressure relief devices designated for no detectable emissions under the provisions of § 60.482–4a(a) and those pressure relief devices complying with § 60.482–4a(c).

(c) An owner or operator must include the information specified in paragraphs (c)(1) and (2) of this section in all semiannual reports in addition to the information required in § 60.487a(c)(2)(i) through (vi):

(1) Number of pressure relief devices for which leaks were detected as required in § 60.5401a(b)(2); and

(2) Number of pressure relief devices for which leaks were not repaired as required in § 60.5401a(b)(3).

§ 60.5423a What additional recordkeeping and reporting requirements apply to my sweetening unit affected facilities at onshore natural gas processing plants?

(a) You must retain records of the calculations and measurements required in § 60.5405a(a) and (b) and § 60.5407a(a) through (g) for at least 2 years following the date of the measurements. This requirement is included under § 60.7(f) of the General Provisions.

(b) You must submit a report of excess emissions to the Administrator in your annual report if you had excess emissions during the reporting period. The excess emissions report must be submitted to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). (CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*https://cdx.epa.gov/*).) You must use the appropriate electronic report in CEDRI for this subpart or an alternate electronic file format consistent with the extensible markup language (XML) schema listed on the CEDRI Web site (*http://www.epa.gov/ttn/chief/cedri/index.html*). If the reporting form specific to this subpart is not available in CEDRI at the time that the report is due, you must submit the report to the Administrator at the appropriate address listed in § 60.4. You must begin submitting reports via CEDRI no later than 90 days after the form becomes available in CEDRI. The report must be submitted by the deadline specified in this subpart, regardless of the method in which the report is submitted. For the purpose of these reports, excess emissions are defined as specified in paragraphs (b)(1) and (2) of this section.

(1) Any 24-hour period (at consistent intervals) during which the average sulfur emission reduction efficiency (R) is less than the minimum required efficiency (Z).

(2) For any affected facility electing to comply with the provisions of § 60.5407a(b)(2), any 24-hour period during which the average temperature of the gases leaving the combustion zone of an incinerator is less than the appropriate operating temperature as determined during the most recent performance test in accordance with the provisions of § 60.5407a(b)(3). Each 24-hour period must consist of at least 96 temperature measurements equally spaced over the 24 hours.

(c) To certify that a facility is exempt from the control requirements of these standards, for each facility with a design capacity less than 2 LT/D of H_2S in the acid gas (expressed as sulfur) you must keep, for the life of the facility, an analysis demonstrating that the facility's design capacity is less than 2 LT/D of H_2S expressed as sulfur.

(d) If you elect to comply with § 60.5407a(e) you must keep, for the life of the facility, a record demonstrating that the facility's design capacity is less than 150 LT/D of H_2S expressed as sulfur.

(e) The requirements of paragraph (b) of this section remain in force until and unless the EPA, in delegating enforcement authority to a state under section 111(c) of the Act, approves reporting requirements or an alternative means of compliance surveillance adopted by such state. In that event, affected sources within the state will be relieved of obligation to comply with paragraph (b) of this section, provided that they comply with the requirements established by the state. Electronic reporting to the EPA cannot be waived, and as such, the provisions of this paragraph do not relieve owners or operators of affected facilities of the requirement to submit the electronic reports required in this section to the EPA.

§ 60.5425a What parts of the General Provisions apply to me?

Table 3 to this subpart shows which parts of the General Provisions in §§ 60.1 through 60.19 apply to you.

§ 60.5430a What definitions apply to this subpart?

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act, in subpart A or subpart VVa of part 60; and the following terms shall have the specific meanings given them.

Acid gas means a gas stream of hydrogen sulfide (H_2S) and carbon dioxide (CO_2) that has been separated from sour natural gas by a sweetening unit.

Alaskan North Slope means the approximately 69,000 square-mile area extending from the Brooks Range to the Arctic Ocean.

API Gravity means the weight per unit volume of hydrocarbon liquids as measured by a system recommended by the American Petroleum Institute (API) and is expressed in degrees.

Bleed rate means the rate in standard cubic feet per hour at which natural gas is continuously vented (bleeds) from a pneumatic controller.

Capital expenditure means, in addition to the definition in 40 CFR 60.2, an expenditure for a physical or operational change to an existing facility that exceeds P, the product of the facility's replacement cost, R, and an adjusted annual asset guideline repair allowance, A, as reflected by the following equation: $P = R \times A$, where:

(1) The adjusted annual asset guideline repair allowance, A, is the product of the percent of the replacement cost, Y, and the applicable basic annual asset guideline repair allowance, B, divided by 100 as reflected by the following equation:

$A = Y \times (B \div 100)$;

(2) The percent Y is determined from the following equation: $Y = 1.0 - 0.575 \log X$, where X is 2011 minus the year of construction; and

(3) The applicable basic annual asset guideline repair allowance, B, is 4.5.

Centrifugal compressor means any machine for raising the pressure of a natural gas by drawing in low pressure natural gas and discharging significantly higher pressure natural gas by means of mechanical rotating vanes or impellers. Screw, sliding vane, and liquid ring compressors are not centrifugal compressors for the purposes of this subpart.

Certifying official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The Administrator is notified of such delegation of authority prior to the exercise of that authority. The Administrator reserves the right to evaluate such delegation;

(2) For a partnership (including but not limited to general partnerships, limited partnerships, and limited liability partnerships) or sole proprietorship: A general partner or the proprietor, respectively. If a general partner is a corporation, the provisions of paragraph (1) of this definition apply;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Chemical/methanol or diaphragm pump means a gas-driven positive displacement pump typically used to inject precise amounts of chemicals into process streams or circulate glycol compounds for freeze protection.

City gate means the delivery point at which natural gas is transferred from a transmission pipeline to the local gas utility.

Collection system means any infrastructure that conveys gas or liquids from the well site to another location for treatment, storage, processing, recycling, disposal or other handling.

Completion combustion device means any ignition device, installed horizontally or vertically, used in exploration and production operations to combust otherwise vented emissions from completions.

Compressor station site means any permanent combination of one or more compressors that move natural gas at increased pressure through gathering or transmission pipelines, or into or out of storage. This includes, but is not limited to, gathering and boosting stations and transmission compressor stations.

Condensate means hydrocarbon liquid separated from natural gas that condenses due to changes in the temperature, pressure, or both, and remains liquid at standard conditions.

Continuous bleed means a continuous flow of pneumatic supply natural gas to a pneumatic controller.

Crude oil and natural gas source category means:

(1) Crude oil production, which includes the well and extends to the point of custody transfer to the crude oil transmission pipeline; and

(2) Natural gas production, processing, transmission, and storage, which include the well and extend to, but do not include, the city gate.

Custody transfer means the transfer of natural gas after processing and/or treatment in the producing operations, or from storage vessels or automatic transfer facilities or other such equipment, including product loading racks, to pipelines or any other forms of transportation.

Dehydrator means a device in which an absorbent directly contacts a natural gas stream and absorbs water in a contact tower or absorption column (absorber).

Deviation means any instance in which an affected source subject to this subpart, or an owner or operator of such a source:

(1) Fails to meet any requirement or obligation established by this subpart including, but not limited to, any emission limit, operating limit, or work practice standard;

(2) 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; or

(3) Fails to meet any emission limit, operating limit, or work practice standard in this subpart during startup, shutdown, or malfunction, regardless of whether or not such failure is permitted by this subpart.

Delineation well means a well drilled in order to determine the boundary of a field or producing reservoir.

Equipment, as used in the standards and requirements in this subpart relative to the equipment leaks of methane and VOC from onshore natural gas processing plants, means each pump, pressure relief device, open-ended valve or line, valve, and flange or other connector that is in VOC service or in wet gas service, and any device or system required by those same standards and requirements in this subpart.

Field gas means feedstock gas entering the natural gas processing plant.

Field gas gathering means the system used transport field gas from a field to the main pipeline in the area.

Flare means a thermal oxidation system using an open (without enclosure) flame. Completion combustion devices as defined in this section are not considered flares.

Flow line means a pipeline used to transport oil and/or gas to a processing facility, a mainline pipeline, re-injection, or routed to a process or other useful purpose.

Flowback means the process of allowing fluids and entrained solids to flow from a well following a treatment, either in preparation for a subsequent phase of treatment or in preparation for cleanup and returning the well to production. The term flowback also means the fluids and entrained solids that emerge from a well during the flowback process. The flowback period begins when material introduced into the well during the treatment returns to the surface following hydraulic fracturing or refracturing. The flowback period ends when either the well is shut in and permanently disconnected from the flowback equipment or at the startup of production. The flowback period includes the initial flowback stage and the separation flowback stage.

Fugitive emissions component means any component that has the potential to emit fugitive emissions of methane or VOC at a well site or compressor station site, including but not limited to valves, connectors, pressure relief devices, open-ended lines, access doors, flanges, closed vent systems, thief hatches or other openings on a storage vessels, agitator seals, distance pieces, crankcase vents, blowdown vents, pump seals or diaphragms, compressors, separators, pressure vessels, dehydrators, heaters, instruments, and meters. Devices that vent as part of normal operations, such as natural gas-driven pneumatic controllers or natural gas-driven pumps, are not fugitive emissions components, insofar as the natural gas discharged from the device's vent is not considered a fugitive emission. Emissions originating from other than the vent, such as the seals around the bellows of a diaphragm pump, would be considered fugitive emissions.

Gas processing plant process unit means equipment assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Hydraulic fracturing means the process of directing pressurized fluids containing any combination of water, proppant, and any added chemicals to penetrate tight formations, such as shale or coal formations, that subsequently require high rate, extended flowback to expel fracture fluids and solids during completions.

Hydraulic refracturing means conducting a subsequent hydraulic fracturing operation at a well that has previously undergone a hydraulic fracturing operation.

In light liquid service means that the piece of equipment contains a liquid that meets the conditions specified in § 60.485a(e) or § 60.5401a(f)(2) of this part.

In wet gas service means that a compressor or piece of equipment contains or contacts the field gas before the extraction step at a gas processing plant process unit.

Initial flowback stage means the period during a well completion operation which begins at the onset of flowback and ends at the separation flowback stage.

Intermediate hydrocarbon liquid means any naturally occurring, unrefined petroleum liquid.

Intermittent/snap-action pneumatic controller means a pneumatic controller that is designed to vent non-continuously.

Liquefied natural gas unit means a unit used to cool natural gas to the point at which it is condensed into a liquid which is colorless, odorless, non-corrosive and non-toxic.

Low pressure well means a well with reservoir pressure and vertical well depth such that 0.445 times the reservoir pressure (in psia) minus 0.038 times the vertical well depth (in feet) minus 67.578 psia is less than the flow line pressure at the sales meter.

Maximum average daily throughput means the earliest calculation of daily average throughput during the 30-day PTE evaluation period employing generally accepted methods.

Natural gas-driven pneumatic controller means a pneumatic controller powered by pressurized natural gas.

Natural gas-driven chemical/methanol or diaphragm pump means a chemical or methanol injection or circulation pump or a diaphragm pump powered by pressurized natural gas.

Natural gas liquids means the hydrocarbons, such as ethane, propane, butane, and pentane that are extracted from field gas.

Natural gas processing plant (gas plant) means any processing site engaged in the extraction of natural gas liquids from field gas, fractionation of mixed natural gas liquids to natural gas products, or both. A Joule-Thompson valve, a dew point depression valve, or an isolated or standalone Joule-Thompson skid is not a natural gas processing plant.

Natural gas transmission means the pipelines used for the long distance transport of natural gas (excluding processing). Specific equipment used in natural gas transmission includes the land, mains, valves, meters, boosters, regulators, storage vessels, dehydrators, compressors, and their driving units and appurtenances, and equipment used for transporting gas from a production plant, delivery point of purchased gas, gathering system, storage area, or other wholesale source of gas to one or more distribution area(s).

Nonfractionating plant means any gas plant that does not fractionate mixed natural gas liquids into natural gas products.

Non-natural gas-driven pneumatic controller means an instrument that is actuated using other sources of power than pressurized natural gas; examples include solar, electric, and instrument air.

Onshore means all facilities except those that are located in the territorial seas or on the outer continental shelf.

Pneumatic controller means an automated instrument used for maintaining a process condition such as liquid level, pressure, delta-pressure and temperature.

Pressure vessel means a storage vessel that is used to store liquids or gases and is designed not to vent to the atmosphere as a result of compression of the vapor headspace in the pressure vessel during filling of the pressure vessel to its design capacity.

Process unit means components assembled for the extraction of natural gas liquids from field gas, the fractionation of the liquids into natural gas products, or other operations associated with the processing of natural gas products. A process unit can operate independently if supplied with sufficient feed or raw materials and sufficient storage facilities for the products.

Produced water means water that is extracted from the earth from an oil or natural gas production well, or that is separated from crude oil, condensate, or natural gas after extraction.

Reciprocating compressor means a piece of equipment that increases the pressure of a process gas by positive displacement, employing linear movement of the driveshaft.

Reciprocating compressor rod packing means a series of flexible rings in machined metal cups that fit around the reciprocating compressor piston rod to create a seal limiting the amount of compressed natural gas that escapes to the atmosphere.

Recovered gas means gas recovered through the separation process during flowback.

Recovered liquids means any crude oil, condensate or produced water recovered through the separation process during flowback.

Reduced emissions completion means a well completion following fracturing or refracturing where gas flowback that is otherwise vented is captured, cleaned, and routed to the flow line or collection system, re-injected into the well or another well, used as an on-site fuel source, or used for other useful purpose that a purchased fuel or raw material would serve, with no direct release to the atmosphere.

Reduced sulfur compounds means H_2S, carbonyl sulfide (COS), and carbon disulfide (CS_2).

Removed from service means that a storage vessel affected facility has been physically isolated and disconnected from the process for a purpose other than maintenance in accordance with § 60.5395a(c)(1).

Responsible official means one of the following:

(1) For a corporation: A president, secretary, treasurer, or vice-president of the corporation in charge of a principal business function, or any other person who performs similar policy or decision-making functions for the corporation, or a duly authorized representative of such person if the representative is responsible for the overall operation of one or more manufacturing, production, or operating facilities applying for or subject to a permit and either:

(i) The facilities employ more than 250 persons or have gross annual sales or expenditures exceeding $25 million (in second quarter 1980 dollars); or

(ii) The delegation of authority to such representatives is approved in advance by the permitting authority;

(2) For a partnership or sole proprietorship: A general partner or the proprietor, respectively;

(3) For a municipality, State, Federal, or other public agency: Either a principal executive officer or ranking elected official. For the purposes of this part, a principal executive officer of a Federal agency includes the chief executive officer having responsibility for the overall operations of a principal geographic unit of the agency (*e.g.,* a Regional Administrator of EPA); or

(4) For affected facilities:

(i) The designated representative in so far as actions, standards, requirements, or prohibitions under title IV of the Clean Air Act or the regulations promulgated thereunder are concerned; or

(ii) The designated representative for any other purposes under part 60.

Returned to service means that a storage vessel affected facility that was removed from service has been:

(1) Reconnected to the original source of liquids or has been used to replace any storage vessel affected facility; or

(2) Installed in any location covered by this subpart and introduced with crude oil, condensate, intermediate hydrocarbon liquids or produced water.

Routed to a process or route to a process means the emissions are conveyed via a closed vent system to any enclosed portion of a process where the emissions are predominantly recycled and/or consumed in the same manner as a material that fulfills the same function in the process and/or transformed by chemical reaction into materials that are not regulated materials and/or incorporated into a product; and/or recovered.

Salable quality gas means natural gas that meets the flow line or collection system operator specifications, regardless of whether such gas is sold.

Separation flowback stage means the period during a well completion operation when it is technically feasible for a separator to function. The separation flowback stage ends either at the startup of production, or when the well is shut in and permanently disconnected from the flowback equipment.

Startup of production means the beginning of initial flow following the end of flowback when there is continuous recovery of salable quality gas and separation and recovery of any crude oil, condensate or produced water.

Storage vessel means a tank or other vessel that contains an accumulation of crude oil, condensate, intermediate hydrocarbon liquids, or produced water, and that is constructed primarily of nonearthen materials (such as wood, concrete, steel, fiberglass, or plastic) which provide structural support. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart. A tank or other vessel shall not be considered a storage vessel if it has been removed from service in accordance with the requirements of § 60.5395a(c) until such time as such tank or other vessel has been returned to service. For the purposes of this subpart, the following are not considered storage vessels:

(1) Vessels that are skid-mounted or permanently attached to something that is mobile (such as trucks, railcars, barges or ships), and are intended to be located at a site for less than 180 consecutive days. If you do not keep or are not able to produce records, as required by § 60.5420a(c)(5)(iv), showing that the vessel has been located at a site for less than 180 consecutive days, the vessel described herein is considered to be a storage vessel from the date the original vessel was first located at the site. This exclusion does not apply to a well completion vessel as described above.

(2) Process vessels such as surge control vessels, bottoms receivers or knockout vessels.

(3) Pressure vessels designed to operate in excess of 204.9 kilopascals and without emissions to the atmosphere.

Sulfur production rate means the rate of liquid sulfur accumulation from the sulfur recovery unit.

Sulfur recovery unit means a process device that recovers element sulfur from acid gas.

Surface site means any combination of one or more graded pad sites, gravel pad sites, foundations, platforms, or the immediate physical location upon which equipment is physically affixed.

Sweetening unit means a process device that removes hydrogen sulfide and/or carbon dioxide from the sour natural gas stream.

Total Reduced Sulfur (TRS) means the sum of the sulfur compounds hydrogen sulfide, methyl mercaptan, dimethyl sulfide, and dimethyl disulfide as measured by Method 16 of appendix A–6 of this part.

Total SO_2 equivalents means the sum of volumetric or mass concentrations of the sulfur compounds obtained by adding the quantity existing as SO_2 to the quantity of SO_2 that would be obtained if all reduced sulfur compounds were converted to SO_2 (ppmv or kg/dscm (lb/dscf)).

Underground storage vessel means a storage vessel stored below ground.

Well means a hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected.

Well completion means the process that allows for the flowback of petroleum or natural gas from newly drilled wells to expel drilling and reservoir fluids and tests the reservoir flow characteristics, which may vent produced hydrocarbons to the atmosphere via an open pit or tank.

Well completion operation means any well completion with hydraulic fracturing or refracturing occurring at a well affected facility.

Well completion vessel means a vessel that contains flowback during a well completion operation following hydraulic fracturing or refracturing. A well completion vessel may be a lined earthen pit, a tank or other vessel that is skid-mounted or portable. A well completion vessel that receives recovered liquids from a well after startup of production following flowback for a period which exceeds 60 days is considered a storage vessel under this subpart.

Well site means one or more areas that are directly disturbed during the drilling and subsequent operation of, or affected by, production facilities directly associated with any oil well, natural gas well, or injection well and its associated well pad. For the purposes of the fugitive emissions standards at § 60.5397a, well site also includes tank batteries collecting crude oil, condensate, intermediate hydrocarbon liquids, or produced water from wells not located at the well site (e.g., centralized tank batteries).

Wellhead means the piping, casing, tubing and connected valves protruding above the earth's surface for an oil and/or natural gas well. The wellhead ends where the flow line connects to a wellhead valve. The wellhead does not include other equipment at the well site except for any conveyance through which gas is vented to the atmosphere.

Wildcat well means a well outside known fields or the first well drilled in an oil or gas field where no other oil and gas production exists.

§§ 60.5431a–60.5499a [Reserved]

TABLE 1 TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM INITIAL SO_2 EMISSION REDUCTION EFFICIENCY (Z_i)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0<X<5.0	5.0<X<15.0	15.0<X<300.0	X>300.0
Y>50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 99.9, whichever is smaller.		
20<Y<50	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 97.9, whichever is smaller.		97.9
10<Y<20	79.0	$88.51X^{0.0101}Y^{0.0125}$ or 93.5, whichever is smaller.	93.5	93.5
Y<10	79.0	79.0	79.0	79.0

TABLE 2—TO SUBPART OOOOa OF PART 60—REQUIRED MINIMUM SO_2 EMISSION REDUCTION EFFICIENCY (Z_c)

H_2S content of acid gas (Y), %	Sulfur feed rate (X), LT/D			
	2.0<X<5.0	5.0<X<15.0	15.0<X<300.0	X>300.0
Y>50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 99.9, whichever is smaller.		
20<Y<50	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 97.5, whichever is smaller.		97.5
10<Y<20	74.0	$85.35X^{0.0144}Y^{0.0128}$ or 90.8, whichever is smaller.	90.8	90.8
Y<10	74.0	74.0	74.0	74.0

X = The sulfur feed rate from the sweetening unit (*i.e.*, the H_2S in the acid gas), expressed as sulfur, Mg/D(LT/D), rounded to one decimal place.

Y = The sulfur content of the acid gas from the sweetening unit, expressed as mole percent H_2S (dry basis) rounded to one decimal place.

Z = The minimum required sulfur dioxide (SO_2) emission reduction efficiency, expressed as percent carried to one decimal place. Zi refers to the reduction efficiency required at the initial performance test. Zc refers to the reduction efficiency required on a continuous basis after compliance with Zi has been demonstrated.

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa

[As stated in § 60.5425a, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.1	General applicability of the General Provisions	Yes	
§ 60.2	Definitions	Yes	Additional terms defined in § 60.5430a.
§ 60.3	Units and abbreviations	Yes	
§ 60.4	Address	Yes	
§ 60.5	Determination of construction or modification	Yes	
§ 60.6	Review of plans	Yes	
§ 60.7	Notification and record keeping	Yes	Except that § 60.7 only applies as specified in § 60.5420a(a).
§ 60.8	Performance tests	Yes	Performance testing is required for control devices used on storage vessels, centrifugal compressors and pneumatic pumps.
§ 60.9	Availability of information	Yes	
§ 60.10	State authority	Yes	
§ 60.11	Compliance with standards and maintenance requirements.	No	Requirements are specified in subpart OOOOa.
§ 60.12	Circumvention	Yes	
§ 60.13	Monitoring requirements	Yes	Continuous monitors are required for storage vessels.

TABLE 3 TO SUBPART OOOOa OF PART 60—APPLICABILITY OF GENERAL PROVISIONS TO SUBPART OOOOa—Continued

[As stated in § 60.5425a, you must comply with the following applicable General Provisions]

General provisions citation	Subject of citation	Applies to subpart?	Explanation
§ 60.14	Modification	Yes	To the extent any provision in § 60.14 conflicts with specific provisions in subpart OOOOa, it is superseded by subpart OOOOa provisions.
§ 60.15	Reconstruction	Yes	Except that § 60.15(d) does not apply to pneumatic controllers, pneumatic pumps, centrifugal compressors or storage vessels.
§ 60.16	Priority list	Yes	
§ 60.17	Incorporations by reference	Yes	
§ 60.18	General control device and work practice requirements.	Yes	
§ 60.19	General notification and reporting requirement	Yes	

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Part III

Environmental Protection Agency

40 CFR Part 63

National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production; Final Rule

ENVIRONMENTAL PROTECTION AGENCY

40 CFR Part 63

[EPA–HQ–OAR–2010–0544; FRL–9932–44–OAR]

RIN 2060–AQ40

National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production

AGENCY: Environmental Protection Agency (EPA).

ACTION: Final rule.

SUMMARY: This action finalizes the residual risk and technology review (RTR), and the rule review, we conducted for the Secondary Aluminum Production source category regulated under national emission standards for hazardous air pollutants (NESHAP). In this action, we are finalizing several amendments to the NESHAP based on the rule review. These final amendments include a requirement to report performance testing through the Electronic Reporting Tool (ERT); provisions allowing owners and operators to change furnace classifications; requirements to account for unmeasured emissions during compliance testing for group 1 furnaces that do not have add-on control devices; alternative compliance options for the operating and monitoring requirements for sweat furnaces; compliance provisions for hydrogen fluoride; provisions addressing emissions during periods of startup, shutdown, and malfunction (SSM); and other corrections and clarifications to the applicability, definitions, operating, monitoring and performance testing requirements. These amendments will improve the monitoring, compliance and implementation of the rule.

DATES: *Effective date:* This final action is effective on September 18, 2015.

Compliance dates: The compliance date for the final amendments listed in 40 CFR 63.1501(b) for existing secondary aluminum production affected sources is March 16, 2016. The compliance date for the final amendments listed in 40 CFR 63.1501(c) for existing affected sources is September 18, 2017. The owner or operator of a new affected source that commences construction or reconstruction after February 14, 2012, must comply with all of the requirements listed in 40 CFR 63.1501(b) and (c) by September 18, 2015 or upon startup, whichever is later.

The incorporation by reference of certain publications listed in the rule is approved by the Director of the Federal Register as of September 18, 2015.

ADDRESSES: The Environmental Protection Agency (EPA) has established a docket for this action under Docket ID No. EPA–HQ–OAR–2010–0544. All documents in the docket are listed on the *www.regulations.gov* Web site. Although listed in the index, some information is not publicly available, *e.g.,* confidential business information (CBI) or other information whose disclosure is restricted by statute. Certain other material, such as copyrighted material, is not placed on the Internet and will be publicly available only in hard copy form. Publicly available docket materials are available either electronically through *http://www.regulations.gov*, or in hard copy at the EPA Docket Center, EPA WJC West Building, Room Number 3334, 1301 Constitution Ave. NW., Washington, DC. The Public Reading Room hours of operation are 8:30 a.m. to 4:30 p.m., Monday through Friday. The telephone number for the Public Reading Room is (202) 566–1744, and the telephone number for the Air Docket is (202) 566–1742.

FOR FURTHER INFORMATION CONTACT: For questions about this final action, contact Ms. Rochelle Boyd, Sector Policies and Programs Division (D243–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, 27711; telephone number: (919) 541–1390; fax number: (919) 541–3207; and email address: *boyd.rochelle@epa.gov.* For specific information regarding the risk modeling methodology, contact James Hirtz, Health and Environmental Impacts Division (C539–02), Office of Air Quality Planning and Standards, U.S. Environmental Protection Agency, Research Triangle Park, North Carolina 27711; telephone number: (919) 541–0881; fax number: (919) 541–0840; and email address: *hirtz.james@epa.gov.* For information about the applicability of the NESHAP to a particular entity, contact Scott Throwe, Office of Enforcement and Compliance Assurance, U.S. Environmental Protection Agency, EPA WJC West Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460; telephone number: (202) 564–7013; and email address: *throwe.scott@epa.gov.*

SUPPLEMENTARY INFORMATION: *Preamble Acronyms and Abbreviations.* We use multiple acronyms and terms in this preamble. While this list may not be exhaustive, to ease the reading of this preamble and for reference purposes, the EPA defines the following terms and acronyms here:

ACGIH American Conference of Government Industrial Hygienists
AEGL acute exposure guideline levels
AERMOD air dispersion model used by the HEM–3 model
APCD air pollution control device
AMOS ample margin of safety
ATSDR Agency for Toxic Substances and Disease Registry
BACT best available control technology
CAA Clean Air Act
CalEPA California Environmental Protection Agency
CBI confidential business information
CDX Central Data Exchange
CFR Code of Federal Regulations
D/F dioxins and furans
Dscf dry standard cubic feet
Dscm dry standard cubic meters
EJ environmental justice
EPA United States Environmental Protection Agency
ERPG Emergency Response Planning Guidelines
ERT Electronic Reporting Tool
g grams
gr grains
HAP hazardous air pollutants
HCl hydrogen chloride
HEM–3 Human Exposure Model, Version 3
HF hydrogen fluoride
HI hazard index
HQ hazard quotient
ICR information collection request
IRIS Integrated Risk Information System
km kilometer
lb pounds
lbs/yr pounds per year
LOAEL lowest-observed-adverse-effect level
MACT maximum achievable control technology
MIR maximum individual risk
NAAQS National Ambient Air Quality Standards
NAICS North American Industry Classification System
NAS National Academy of Sciences
NATA National Air Toxics Assessment
NEI National Emissions Inventory
NESHAP National Emission Standards for Hazardous Air Pollutants
NOAEL no observed adverse effects level
NRC National Research Council
NTTAA National Technology Transfer and Advancement Act
O&M operation and maintenance
OAQPS Office of Air Quality Planning and Standards
OECA Office of Enforcement and Compliance Assurance
OMB Office of Management and Budget
OM&M operation, maintenance and monitoring
PAH polycyclic aromatic hydrocarbons
PB–HAP hazardous air pollutants known to be persistent and bio-accumulative in the environment
PEL probable effect levels
PM particulate matter
POM polycyclic organic matter
REL reference exposure level
RFA Regulatory Flexibility Act
RfC reference concentration
RfD reference dose
RTR Risk and Technology Review
SAB Science Advisory Board

SAPU secondary aluminum processing unit
SBA Small Business Administration
SOP standard operating procedures
SSM startup, shutdown, and malfunction
TEQ toxicity equivalents
THC total hydrocarbons
TOSHI target organ-specific hazard index
tpy tons per year
TRIM.FaTE Total Risk Integrated Methodology Fate, Transport and Ecological Exposure model
TTN Technology Transfer Network
UBC used beverage containers
UF uncertainty factor
μ/m3 microgram per cubic meter
UMRA Unfunded Mandates Reform Act
UPL upper prediction limit
URE unit risk estimate

Background Information. On February 14, 2012, and December 8, 2014, the EPA proposed decisions based on the RTR and proposed revisions to the Secondary Aluminum Production NESHAP based on review of the rule. In this action, we are finalizing decisions and revisions to the rule. We summarize major comments we timely received regarding the proposed rule and provide responses in this preamble. A summary of all other public comments on the proposal and the EPA's responses to those comments is available in the document, National Emission Standards for Hazardous Air Pollutants: Secondary Aluminum Production. Summary of Public Comments and Responses on Proposed Rule (77 FR 8576, February 14, 2012) and Supplemental Proposal (79 FR 72874, December 8, 2014), Docket ID No. EPA–HQ–OAR–2010–0544. A ''track changes'' version of the regulatory language that shows the regulatory changes in this action is also available in the docket for the convenience of the reader.

Organization of this Document. The information in this preamble is organized as follows:

I. General Information
A. Does this action apply to me?
B. Where can I get a copy of this document and other related information?
C. Judicial Review and Administrative Reconsideration
II. Background
A. What is the statutory authority for this action?
B. What is the Secondary Aluminum Production source category and how does the NESHAP regulate HAP emissions from the source category?
C. What changes did we propose for the Secondary Aluminum Production source category in our February 14, 2012, and December 8, 2014, proposals?
III. What is included in this final rule?
A. What are the final rule amendments based on the risk review for the Secondary Aluminum Production source category?
B. What are the final rule amendments based on the technology review for the Secondary Aluminum Production source category?
C. What are the final rule amendments addressing emissions during periods of startup, shutdown, and malfunction?
D. What other changes have been made to the NESHAP?
E. What are the effective and compliance dates of the standards?
F. What are the requirements for submission of performance test data to the EPA?
G. What materials are being incorporated by reference?
IV. What is the rationale for our final decisions and amendments for the Secondary Aluminum Production source category?
A. Residual Risk Review for the Secondary Aluminum Production Source Category
B. Technology Review for the Secondary Aluminum Production Source Category
C. Testing of Group 1 Furnaces That Do Not Have Add-on Pollution Control Devices
D. Changing Furnace Classification
E. Flow Rate Measurements and Annual Inspections of Capture/Collection Systems
F. Compliance Dates
V. Summary of Cost, Environmental and Economic Impacts and Additional Analyses Conducted
A. What are the affected sources?
B. What are the air quality impacts?
C. What are the cost impacts?
D. What are the economic impacts?
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F. What analysis of environmental justice did we conduct?
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VI. Statutory and Executive Order Reviews
A. Executive Orders 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review
B. Paperwork Reduction Act (PRA)
C. Regulatory Flexibility Act (RFA)
D. Unfunded Mandates Reform Act (UMRA)
E. Executive Order 13132: Federalism
F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments
G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks
H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use
I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51
J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations
K. Congressional Review Act (CRA)

I. General Information

A. Does this action apply to me?

Regulated Entities. Categories and entities potentially regulated by this action are shown in Table 1 of this preamble.

TABLE 1—INDUSTRIAL SOURCE CATEGORIES AFFECTED BY THIS FINAL ACTION

Source category	NAICS code [a]
Primary Aluminum Production Facilities	331312
Secondary Aluminum Production Facilities	331314
Aluminum Sheet, Plate, and Foil Manufacturing Facilities	331315
Aluminum Extruded Product Manufacturing Facilities	331316
Other Aluminum Rolling and Drawing Facilities	331319
Aluminum Die Casting Facilities	331521
Aluminum Foundry Facilities	331524

[a] North American Industry Classification System.

Table 1 of this preamble is not intended to be exhaustive, but rather to provide a guide for readers regarding entities likely to be affected by the final action for the secondary aluminum production source category. To determine whether your facility is affected, you should examine the applicability criteria in the appropriate NESHAP. If you have any questions regarding the applicability of any aspect of this NESHAP, please contact the appropriate person listed in the preceding **FOR FURTHER INFORMATION CONTACT** section of this preamble.

B. Where can I get a copy of this document and other related information?

In addition to being available in the docket, an electronic copy of this final action will be available on the Internet through the Technology Transfer Network (TTN) Web site, a forum for information and technology exchange in various areas of air pollution control. Following signature by the EPA Administrator, the EPA will post a copy of this final action at *http://www.epa.gov/ttn/atw/alum2nd/alum2pg.html.* Following publication in the **Federal Register**, the EPA will post the **Federal Register** version at this same Web site.

Additional information is available on the (RTR) Web site at *http://www.epa.gov/ttn/atw/rrisk/rtrpg.html.* This information includes an overview of the RTR program, and links to project Web sites for the RTR source categories.

C. Judicial Review and Administrative Reconsideration

Under Clean Air Act (CAA) section 307(b)(1), judicial review of this final action is available only by filing a petition for review in the United States Court of Appeals for the District of Columbia Circuit by November 17, 2015. 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 the EPA to enforce the requirements.

Section 307(d)(7)(B) of the CAA further provides that ''[o]nly an objection to a rule or procedure which was raised with reasonable specificity during the period for public comment (including any public hearing) may be raised during judicial review.'' This section also provides a mechanism for the EPA to reconsider the rule ''[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 should submit a Petition for Reconsideration to the Office of the Administrator, U.S. EPA, Room 3000, EPA WJC West Building, 1200 Pennsylvania Ave. NW., Washington, DC 20460, with a copy to both the person(s) 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), U.S. EPA, 1200 Pennsylvania Ave. NW., Washington, DC 20460.

II. Background

A. What is the statutory authority for this action?

Section 112 of the CAA establishes a two-stage regulatory process to address emissions of hazardous air pollutants (HAP) from stationary sources. In the first stage, we must identify categories of sources emitting one or more of the HAP listed in CAA section 112(b) and then promulgate technology-based NESHAP for those sources. ''Major sources'' are those that emit, or have the potential to emit, any single HAP at a rate of 10 tons per year (tpy) or more, or 25 tpy or more of any combination of HAP. For major sources, these standards are commonly referred to as maximum achievable control technology (MACT) standards and must reflect the maximum degree of emission reductions of HAP achievable (after considering cost, energy requirements, and non-air quality health and environmental impacts). In developing MACT standards, CAA section 112(d)(2) directs the EPA to consider the application of measures, processes, methods, systems, or techniques, including but not limited to those that reduce the volume of or eliminate HAP emissions through process changes, substitution of materials, or other modifications; enclose systems or processes to eliminate emissions; collect, capture, or treat HAP when released from a process, stack, storage, or fugitive emissions point; are design, equipment, work practice, or operational standards; or any combination of the above.

For these MACT standards, the statute specifies certain minimum stringency requirements, which are referred to as MACT floor requirements, and which may not be based on cost considerations. See CAA section 112(d)(3). For new sources, the MACT floor cannot be less stringent than the emission control achieved in practice by the best-controlled similar source. The MACT standards for existing sources can be less stringent than floors for new sources, but they cannot be less stringent than the average emission limitation achieved by the best-performing 12 percent of existing sources in the category or subcategory (or the best-performing five sources for categories or subcategories with fewer than 30 sources). In developing MACT standards, we must also consider control options that are more stringent than the floor, under CAA section 112(d)(2). We may establish standards more stringent than the floor, based on the consideration of the cost of achieving the emissions reductions, any non-air quality health and environmental impacts, and energy requirements.

In the second stage of the regulatory process, the CAA requires the EPA to undertake two different analyses, which we refer to as the technology review and the residual risk review. Under the technology review, we must review the technology-based standards and revise them ''as necessary (taking into account developments in practices, processes, and control technologies)'' no less frequently than every 8 years, pursuant to CAA section 112(d)(6). Under the residual risk review, we must evaluate the risk to public health remaining after application of the technology-based standards and revise the standards, if necessary, to provide an ample margin of safety to protect public health or to prevent, taking into consideration costs, energy, safety, and other relevant factors, an adverse environmental effect. The residual risk review is required within 8 years after promulgation of the technology-based standards, pursuant to CAA section 112(f). In conducting the residual risk review, if the EPA determines that the current standards provide an ample margin of safety to protect public health, it is not necessary to revise the MACT standards pursuant to CAA section 112(f).[1] For more information on the statutory authority for this rule, see 77 FR 8576 and 79 FR 72874.

B. What is the Secondary Aluminum Production source category and how does the NESHAP regulate HAP emissions from the source category?

The EPA initially promulgated the Secondary Aluminum Production NESHAP on March 23, 2000 (65 FR 15690). The rule was amended on December 30, 2002 (67 FR 79808), September 3, 2004 (69 FR 53980), October 3, 2005 (70 FR 57513), and December 19, 2005 (70 FR 75320). The standards are codified at 40 CFR part 63, subpart RRR. The existing Subpart RRR NESHAP regulates HAP emissions from secondary aluminum production facilities that are major sources of HAP and that operate aluminum scrap shredders, thermal chip dryers, scrap dryers/delacquering kilns/decoating kilns, group 1 furnaces, group 2 furnaces, sweat furnaces, dross only furnaces, rotary dross coolers, and secondary aluminum processing units (SAPUs). The SAPUs include group 1 furnaces and in-line fluxers. The Subpart RRR NESHAP regulates HAP emissions from secondary aluminum production facilities that are area sources of HAP only with respect to emissions of dioxins/furans (D/F) from thermal chip dryers, scrap dryers/delacquering kilns/decoating kilns, group 1 furnaces, sweat furnaces, and SAPUs. The secondary aluminum industry consists of approximately 161 secondary aluminum production facilities, of which the EPA estimates 53 to be major sources of HAP. Several of the secondary aluminum facilities are co-located with primary aluminum, coil coating, and possibly other source category facilities. Natural gas boilers or process heaters may also be co-located at a few secondary aluminum facilities.

The standards promulgated in 2000 established emission limits for particulate matter (PM) as a surrogate for metal HAP, total hydrocarbons (THC) as a surrogate for organic HAP

[1] The U.S. Court of Appeals for the District of Columbia Circuit has affirmed this approach of implementing CAA section 112(f)(2)(A). *NRC v. EPA,* 529 F.3d 1077, 1083 (D.C. Cir. 2008) (''If EPA determines that the existing technology-based standards provide an 'ample margin of safety,' then the Agency is free to readopt those standards during the residual risk rulemaking.'').

other than D/F, D/F expressed as toxicity equivalents (TEQ), and hydrogen chloride (HCl) as a surrogate for acid gases including hydrogen fluoride (HF), chlorine, and fluorine. HAP are emitted from the following affected sources: Aluminum scrap shredders (subject to PM standards), thermal chip dryers (subject to standards for THC and D/F), scrap dryers/delacquering kilns/decoating kilns (subject to standards for PM, D/F, HCl, and THC), sweat furnaces (subject to D/F standards), dross-only furnaces (subject to PM standards), rotary dross coolers (subject to PM standards), group 1 furnaces (subject to standards for PM, HCl, and D/F), and in-line fluxers (subject to standards for PM and HCl). Group 2 furnaces and certain in-line fluxers are subject to work practice standards. For a more detailed description of the industry, processes, and the key requirements of the MACT rule, see the 2014 supplemental proposal (79 FR 72879, December 8, 2014).

C. What changes did we propose for the Secondary Aluminum Production source category in our February 14, 2012, and December 8, 2014, proposals?

On February 14, 2012, the EPA published a proposed rule in the **Federal Register** (77 FR 8576) for the Secondary Aluminum Production NESHAP, 40 CFR part 63, subpart RRR, that took into consideration the RTR analyses and other reviews of the MACT rule. We proposed that no amendments to Subpart RRR were necessary as a result of the RTR analyses. However, we proposed several amendments to correct and clarify existing requirements based on other reviews of the rule, including:

- Proposed criteria and procedures for changing furnace classification (*i.e.,* operating mode) and a limit on frequency of switching furnace classification of once per 6-month period, with an exception for control device maintenance requiring shutdown;
- Proposed amendments to clarify that performance tests under multiple scenarios may be required in order to reflect the emissions ranges for each regulated pollutant;
- Proposed compliance alternatives for testing of furnaces that do not have add-on air pollution control devices (also referred to as ''uncontrolled furnaces''), *i.e.,* either temporary installation of American Conference of Governmental Industrial Hygienists (ACGIH) hooding or, for existing uncontrolled furnaces, use of an assumption of 67-percent capture efficiency for furnace exhaust. If the source fails to demonstrate compliance using the 67-percent capture efficiency assumption, the source would have to retest within 90 days using hooding that meets ACGIH guidelines or submit a petition that such hoods are impractical and propose alternative testing procedures that will minimize unmeasured fugitive emissions;
- With regard to annual inspections of capture/collection systems, proposed codification of our existing interpretation that annual hood inspections include flow rate measurements using EPA Reference Methods 1 and 2;
- Proposed removal of exemptions from the requirement to comply with 40 CFR part 63, subpart RRR emission standards during periods of startup, shutdown, and malfunction (SSM), clarification of related provisions, and an alternative method for demonstrating compliance with certain emission limits during startup and shutdown;
- Proposed requirement for electronic submission of test results to increase the ease and efficiency of data submittal and improve data accessibility; and
- Proposed compliance date for existing affected sources to comply with the proposed amendments within 90 days after publication of the final rule.

In the 2012 proposal, we also proposed several other corrections and clarifications of the rule on the following topics based on recommendations and suggestions from individual representatives from state regulatory agencies and industry, as well as based on EPA experience, to correct errors in the rule and to help clarify the intent and implementation of the rule:

- ACGIH Guidelines;
- Testing worst-case scenarios;
- Lime injection rate;
- Flux monitoring;
- Cover flux;
- Capture and collection system definition;
- Bale breakers;
- Bag Leak Detection Systems (BLDS);
- Sidewell furnaces;
- Testing representative units;
- Initial performance tests;
- Scrap dryer/delacquering/decoating kiln and scrap shredder definitions;
- Group 2 furnace definition;
- HF emissions compliance;
- SAPU definition;
- Clean charge definition;
- Residence time definition;
- SAPU feed/charge rate;
- Dross-only versus dross/scrap furnaces;
- Applicability of rule to area sources;
- Altering parameters during testing with new scrap streams;
- Controlled furnaces that are temporarily idled for 24 hours or longer; and
- Annual compliance certification for area sources.

In the December 8, 2014, supplemental proposal (79 FR 72874), we presented a revised risk review and a revised technology review. Similar to the 2012 proposal, we found risks due to emissions of air toxics to be acceptable from this source category and we identified no cost-effective controls under the updated AMOS analysis or the technology review to achieve further emissions reductions. We proposed no revisions to the emission standards based on the revised risk and technology review. However, in the 2014 supplemental proposal, we supplemented and modified several of the proposed technical corrections and rule clarifications from the 2012 proposal, including the following:

- Revised proposed limit on the total number of furnace operating mode changes (*i.e.,* frequency) of four times in any 6-month period, with the ability of sources to apply to the appropriate authority for additional furnace operating mode changes;
- Revised wording in proposed 40 CFR 63.1511(b)(1) related to worst-case scenario testing clarifying under what conditions the performance tests are to be conducted;
- Revised proposed compliance requirements for performance testing of uncontrolled furnaces, such that if a source: (1) Chooses to use an assumption of 67-percent[2] capture/collection efficiency, instead of installing temporary hooding according to ACGIH guidelines, and (2) fails to demonstrate compliance using the 67-percent efficiency assumption, then the source must either retest using ACGIH hooding within 180 days (rather than the 90 days specified in the 2012 proposal) or petition the appropriate authority within 180 days that installing ACGIH hooding is impractical and propose alternative testing procedures that will minimize unmeasured emissions;
- Revised proposed requirement that emission sources comply with the emissions limits at all times, including periods of SSM. Proposed definitions of startup and shutdown as well as an additional alternative method for demonstrating compliance with certain emission limits during startup and shutdown;
- Revised proposed requirements for annual inspection of capture/collection

[2] The capture efficiency of 66.67 percent was rounded to 67 percent.

systems to allow additional compliance options;

- Revised proposed compliance dates of 180 days for certain requirements and 2 years for other requirements; and
- Revised operating and monitoring requirements for sweat furnaces to allow an additional compliance option.

In addition, we withdrew our 2012 proposal to include provisions establishing an affirmative defense in light of a recent court decision vacating an affirmative defense in one of the EPA's CAA section 112(d) regulations. *NRDC v. EPA,* 749 F.3d 1055 (D.C. Cir. 2014) (vacating affirmative defense provisions in CAA section 112(d) rule establishing emission standards for Portland cement kilns).

III. What is included in this final rule?

This action finalizes the EPA's determinations pursuant to the RTR provisions of CAA section 112 for the Secondary Aluminum Production source category. This action also finalizes changes to the NESHAP, including technical corrections and rule clarifications as well as alternative compliance options.

A. What are the final rule amendments based on the risk review for the Secondary Aluminum Production source category?

There are no rule amendments based on the risk review for this source category.

B. What are the final rule amendments based on the technology review for the Secondary Aluminum Production source category?

There are no rule amendments based on the technology review for this source category.

C. What are the final rule amendments addressing emissions during periods of startup, shutdown, and malfunction?

In its 2008 decision in *Sierra Club v. EPA*, 551 F.3d 1019 (D.C. Cir. 2008), the United States Court of Appeals for the District of Columbia Circuit vacated portions of two provisions in the EPA's CAA section 112 regulations governing the emissions of HAP during periods SSM. Specifically, the Court vacated the SSM exemption contained in 40 CFR 63.6(f)(1) and 40 CFR 63.6(h)(1), holding that under section 302(k) of the CAA, emissions standards or limitations must be continuous in nature and that the SSM exemption violates the CAA's requirement that some section 112 standards apply continuously.

We have eliminated the SSM exemption in this rule. Consistent with *Sierra Club* v. *EPA*, the EPA has established standards in this rule that apply at all times. We have also revised Appendix A to Subpart RRR of part 63 (the General Provisions applicability table) in several respects as is explained in more detail below. For example, we have eliminated the incorporation of the General Provisions' requirement that the source develop an SSM plan. We have also eliminated and revised certain recordkeeping and reporting that is related to the SSM exemption as described in detail in the proposed rule and summarized again here.

In establishing the standards in this rule, the EPA has taken into account startup and shutdown periods and, for the reasons explained below, has not established alternate emission standards for those periods.

We are finalizing amendments to eliminate provisions that exempt sources from the requirement to comply with the otherwise applicable CAA section 112(d) emission standards during periods of SSM. As explained in the 2012 proposal and 2014 supplemental proposal, because the scrap processed at secondary aluminum production facilities is the source of emissions, we expect emissions during startup and shutdown would be no higher, and most likely significantly lower, than emissions during normal operations since no scrap is processed during those periods. The final amendments include alternative methods for demonstrating compliance with applicable emission limits that are expressed in units of pounds per ton of feed/charge, or microgram (μg) TEQ or nanogram (ng) TEQ per megagram (Mg) of feed/charge, based on emissions during startup and shutdown and, alternatively, demonstrating compliance by keeping records that show that during startup and shutdown, the feed/charge rate was zero, the flux rate was zero, and the affected source or emission unit was heated with electricity, propane, or natural gas as the sole sources of heat or was not heated. See 40 CFR 63.1513(f).

We are also finalizing definitions for the periods of startup and shutdown to account for the fact that many furnaces are batch operations and are often in a standby condition that, under the proposed definitions, might have been considered to be shutdown. The final definition of shutdown recognizes that shutdown begins when the addition of feed/charge is halted, the heat sources are removed, and product is removed from the equipment to the greatest extent practicable, and ends when the equipment cools to near ambient temperature. The final definition recognizes that, after tapping, most furnaces (tilting furnaces are an exception) retain a molten metal heel and are not emptied completely. In the final amendments, startup is defined as beginning with equipment warming from a shutdown and ending at the point that feed/charge or flux is introduced.

Other SSM-related changes include:

- Revising 40 CFR 63.1510(s)(2)(iv), 63.1515(b)(10), 63.1516(a), 63.1516(b)(1)(v), and 63.1517(b)(16)(i) to reflect the revised requirements related to periods of SSM;
- Revising 40 CFR 63.1506(a)(5) to incorporate the general duty from 40 CFR 63.6(e)(1)(i) to minimize emissions; and
- Adding 40 CFR 63.1516(d), and 40 CFR 63.1517(b)(18) and (19) to require reporting and recordkeeping associated with periods of SSM.

Periods of startup, normal operations, and shutdown are all predictable and routine aspects of a source's operations. Malfunctions, in contrast, are neither predictable nor routine. Instead, they are, by definition, sudden, infrequent, and not reasonably preventable failures of emissions control, process, or monitoring equipment (40 CFR 63.2) (Definition of malfunction). The EPA interprets CAA section 112 as not requiring emissions that occur during periods of malfunction to 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 section 112 that directs the Agency to consider malfunctions in determining the level ''achieved'' by the best performing sources when setting emission standards. As the D.C. Circuit has recognized, the phrase ''average emissions limitation achieved by the best performing 12 percent of'' sources ''says nothing about how the performance of the best units is to be calculated.'' *Nat'l Ass'n of Clean Water Agencies* v. *EPA*, 734 F.3d 1115, 1141 (D.C. Cir. 2013). While the EPA accounts for variability in setting emissions standards, nothing in CAA section 112 requires the Agency to consider malfunctions as part of that analysis. A malfunction should not be treated in the same manner as the type of variation in performance that occurs during routine operations of a source. A malfunction is a failure of the source to perform in a ''normal or usual manner'' and no statutory language compels the

EPA to consider such events in setting CAA section 112 standards.

Further, accounting for malfunctions in setting emission standards 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, emissions during a malfunction event can be significantly higher than emissions at any other time of source operation. For example, if an air pollution control device with 99-percent removal goes off-line as a result of a malfunction (as might happen if, for example, the bags in a baghouse catch fire) and the emission unit is a steady state type unit that would take days to shutdown, the source would go from 99-percent control to zero control until the control device was repaired. The source's emissions during the malfunction would be 100 times higher than during normal operations. As such, the emissions over a 4-day malfunction period would exceed the annual emissions of the source during normal operations. As this example illustrates, accounting for malfunctions could lead to standards that are not reflective of (and significantly less stringent than) levels that are achieved by a well-performing non-malfunctioning source. It is reasonable to interpret CAA section 112 to avoid such a result. The EPA's approach to malfunctions is consistent with CAA section 112 and is a reasonable interpretation of the statute.

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 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 not caused in part by poor maintenance or careless operation. 40 CFR 63.2 (Definition of malfunction).

If the EPA determines in a particular case that an enforcement action against a source for violation of an emission standard is warranted, the source can raise any and all defenses in that enforcement action and the federal district court will determine what, if any, relief is appropriate. The same is true for citizen enforcement actions. Similarly, the presiding officer in an administrative proceeding can consider any defense raised and determine whether administrative penalties are appropriate. In summary, the EPA interpretation of the CAA and, in particular, CAA section 112 is reasonable and encourages practices that will avoid malfunctions. Administrative and judicial procedures for addressing exceedances of the standards fully recognize that violations may occur despite good faith efforts to comply and can accommodate those situations.

In the 2012 proposed rule, the EPA proposed to include an affirmative defense to civil penalties for violations caused by malfunctions. Although the EPA recognized that its case-by-case enforcement discretion provides sufficient flexibility, it proposed to include the affirmative defense to provide a more formalized approach and more regulatory clarity. See *Weyerhaeuser Co.* v. *Costle*, 590 F.2d 1011, 1057–58 (D.C. Cir. 1978) (holding that an informal case-by-case enforcement discretion approach is adequate); but see *Marathon Oil Co.* v. *EPA*, 564 F.2d 1253, 1272–73 (9th Cir. 1977) (requiring a more formalized approach to consideration of ''upsets beyond the control of the permit holder.''). Under the proposed regulatory affirmative defense provisions, if a source could demonstrate in a judicial or administrative proceeding that it had met the requirements of the affirmative defense in the regulation, civil penalties would not be assessed. After the 2012 proposal, the United States Court of Appeals for the District of Columbia Circuit vacated an affirmative defense in one of the EPA's CAA section 112 regulations. *NRDC* v. *EPA*, 749 F.3d 1055 (D.C. Cir., 2014) (vacating affirmative defense provisions in CAA section 112 rule establishing emission standards for Portland cement kilns). The Court found that the EPA lacked authority to establish an affirmative defense for private civil suits and held that under the CAA, the authority to determine civil penalty amounts in such cases lies exclusively with the courts, not the EPA. Specifically, the Court found: ''As the language of the statute makes clear, the courts determine, on a case-by-case basis, whether civil penalties are 'appropriate.' '' See *NRDC* at 1063 (''[U]nder this statute, deciding whether penalties are 'appropriate' in a given private civil suit is a job for the courts, not EPA.'').[3] In light of *NRDC*, the EPA in the 2014 supplemental proposal withdrew the proposed affirmative defense and is not including a regulatory affirmative defense provision in the final rule. As explained above, if a source is unable to comply with emissions standards as a result of a malfunction, the EPA may use its case-by-case enforcement discretion to provide flexibility, as appropriate. Further, as the D.C. Circuit recognized, in an EPA or citizen enforcement action, the court has the discretion to consider any defense raised and determine whether penalties are appropriate. Cf. *NRDC* at 1064 (arguments that violation were caused by unavoidable technology failure can be made to the courts in future civil cases when the issue arises). The same is true for the presiding officer in EPA administrative enforcement actions.[4]

We are revising the General Provisions table (Appendix A to Subpart RRR of 40 CFR part 63) entry for 40 CFR 63.6(e)(1)(i) by changing the ''yes'' in

[3] The Court's reasoning in *NRDC* focuses on civil judicial actions. The Court noted that ''EPA's ability to determine whether penalties should be assessed for Clean Air Act violations extends only to administrative penalties, not to civil penalties imposed by a court.'' *Id.*

[4] Although the *NRDC* case does not address the EPA's authority to establish an affirmative defense to penalties that is available in administrative enforcement actions, the EPA is not including such an affirmative defense in the final rule. As explained above, such an affirmative defense is not necessary, and in the 2014 supplemental proposal, we withdrew the proposed affirmative defense. Moreover, assessment of penalties for violatiing caused by malfunctions in administrative proceedings and judicial proceedings should be consistent, Cf. CAA section 113(e) (requiring both the Administrator and the Court to take specified criteria into account when assessing penalties).

column ''Applies to RRR'' to ''no.'' Section 63.6(e)(1)(i) describes the general duty to minimize emissions. Some of the language in that section is no longer necessary or appropriate in light of the elimination of the SSM exemption. We have instead added general duty regulatory text at 40 CFR 63.1506(a)(5) that reflects the general duty to minimize emissions while eliminating the reference to periods covered by an SSM exemption. The current language in 40 CFR 63.6(e)(1)(i) characterizes what the general duty entails during periods of SSM. With the elimination of the SSM exemption, there is no need to differentiate between normal operations, startup and shutdown, and malfunction events in describing the general duty. Therefore, the language the EPA is promulgating for Subpart RRR does not include that language from 40 CFR 63.6(e)(1).

We are also revising the General Provisions table entry for 40 CFR 63.6(e)(1)(ii) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Section 63.6(e)(1)(ii) imposes requirements that are not necessary with the elimination of the SSM exemption or are redundant with the general duty requirement being added at 40 CFR 63.1506(a)(5).

We are revising the General Provisions table entry for 40 CFR 63.6(e)(3) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Generally, these paragraphs require development of an SSM plan and specify SSM recordkeeping and reporting requirements related to the SSM plan. As noted, the EPA is removing the SSM exemptions. Therefore, affected units will be subject to an emission standard during such events. The applicability of a standard during such events will ensure that sources have ample incentive to plan for and achieve compliance and, thus, the SSM plan requirements are no longer necessary.

We are revising the General Provisions table entry for 40 CFR 63.6(f)(1) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' The current language of 40 CFR 63.6(f)(1) exempts sources from non-opacity standards during periods of SSM. As discussed above, the Court in *Sierra Club* vacated the exemptions contained in this provision and held that the CAA requires that some section 112 standards apply continuously. Consistent with *Sierra Club*, the EPA is revising standards in this rule to apply at all times.

We are revising the General Provisions table entry for 40 CFR 63.6(h)(1) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' The current language of 40 CFR 63.6(h)(1) exempts sources from opacity standards during periods of SSM. As discussed above, the Court in *Sierra Club* vacated the exemptions contained in this provision and held that the CAA requires that some section 112 standards apply continuously. Consistent with *Sierra Club*, the EPA is revising standards in this rule to apply at all times.

We are revising the General Provisions table entry for 40 CFR 63.7(e)(1) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Section 63.7(e)(1) describes performance testing requirements. The EPA is instead adding a performance testing requirement at 40 CFR 63.1513(f). The performance testing requirements we are adding differ from the General Provisions performance testing provisions in several respects. The regulatory text does not include the language in 40 CFR 63.7(e)(1) that restated the SSM exemption and language that precluded startup and shutdown periods from being considered ''representative'' for purposes of performance testing. The revised performance testing provisions include alternative methods for demonstrating compliance with emission limits that are expressed in units of pounds per ton of feed/charge, or µg TEQ or ng TEQ per Mg of feed/charge. Compliance with such limits during startup and shutdown can be demonstrated using the emissions measured during startup and shutdown along with the measured feed/charge rate from the most recent performance test associated with a production rate greater than zero, or the rated capacity of the affected source if no prior performance test data are available. Alternatively, compliance can be demonstrated by keeping records that show that during startup and shutdown, the feed/charge rate was zero, the flux rate was zero, and the affected source or emission unit either was heated with electricity, propane, or natural gas as the sole sources of heat or was not heated. As in 40 CFR 63.7(e)(1), we are requiring in 40 CFR 63.1511(b) that performance tests conducted under this subpart not be conducted during malfunctions because conditions during malfunctions are often not representative of normal operating conditions. The EPA is adding language in 40 CFR 63.1517(b)(19) that requires the owner or operator to record the process information that is necessary to document operating conditions during the test and include in such record an explanation to support that such conditions are representative of startup and shutdown operations. Section 63.7(e) requires that the owner or operator make available to the Administrator such records ''as may be necessary to determine the condition of the performance test'' available to the Administrator upon request, but does not specifically require the information to be recorded. The regulatory text the EPA is adding to this provision builds on that requirement and makes explicit the requirement to record the information.

We are revising the General Provisions table (Appendix A to Subpart RRR of 40 CFR part 63) entry for 40 CFR 63.8(c)(1)(i) and (iii) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' The cross-references to the general duty and SSM plan requirements in those subparagraphs are not necessary in light of other requirements of 40 CFR 63.8 that require good air pollution control practices (40 CFR 63.8(c)(1)) and that set out the requirements of a quality control program for monitoring equipment (40 CFR 63.8(d)).

We are revising the General Provisions table entry for 40 CFR 63.8((d)(3) by changing the ''yes'' in column ''Applies to RRR'' to ''Yes, except for last sentence which refers to an SSM plan. SSM plans are not required.'' The final sentence in 40 CFR 63.8((d)(3) refers to the General Provisions' SSM plan requirement which is no longer applicable.

We are revising the General Provisions table entry for 40 CFR 63.10(b)(2)(i) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Section 63.10(b)(2)(i) describes the recordkeeping requirements during startup and shutdown. These recording provisions are no longer necessary because the EPA is promulgating that recordkeeping and reporting applicable to normal operations will apply to startup and shutdown. In the absence of special provisions applicable to startup and shutdown, such as a startup and shutdown plan, there is no reason to retain additional records for startup and shutdown periods. However, we are adding an additional recordkeeping provision at 40 CFR 63.1517(b)(18) for owners and operators that wish to demonstrate compliance with emission limits that are expressed in units of pounds per ton of feed/charge, or µg TEQ or ng TEQ per Mg of feed/charge, during startup and shutdown by keeping records that show that during startup and shutdown no feed/charge or flux was added, only clean fuel was used, or no fuel was used.

We are revising the General Provisions table entry for 40 CFR 63.10(b)(2)(ii) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Section 63.10(b)(2)(ii) describes the recordkeeping requirements during a malfunction. The EPA is adding such requirements to 40 CFR 63.1517. The regulatory text we are adding differs from the General Provisions it is replacing in that the General Provisions require the creation and retention of a record of the occurrence and duration of each malfunction of process, air pollution control, and monitoring equipment. The EPA is applying the recordkeeping requirement to any failure to meet an applicable standard and is requiring that the source record the date, time, and duration of the failure rather than the ''occurrence.''

We are revising the General Provisions table entry for 40 CFR 63.10(b)(2)(iv) by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' When applicable, the provision requires sources to record actions taken during SSM events when actions were inconsistent with their SSM plan. The requirement is no longer appropriate because SSM plans will no longer be required. The requirement previously applicable under 40 CFR 63.10(b)(2)(iv)(B) to record actions to minimize emissions and record corrective actions is now applicable by reference to 40 CFR 63.1517.

We are revising the General Provisions table entry for 40 CFR 63.10(b)(2)(v) by changing the ''yes'' to ''no.'' When applicable, the provision requires sources to record actions taken during SSM events to show that actions taken were consistent with their SSM plan. The requirement is no longer appropriate because SSM plans will no longer be required.

We are revising the General Provisions table entry for 40 CFR 63.10(c)(15) by changing the ''yes'' to ''no.'' When applicable, the provision allows an owner or operator to use the affected source's SSM plan or records kept to satisfy the recordkeeping requirements of the SSM plan, specified in 40 CFR 63.6(e), to also satisfy the requirements of 40 CFR 63.10(c)(10) through (12). The EPA is eliminating this requirement because SSM plans will no longer be required, and, therefore, 40 CFR 63.10(c)(15) no longer serves any useful purpose.

We are revising the General Provisions table entry for 40 CFR 63.10(d)(5), including (5)(i) and (ii), by changing the ''yes'' in column ''Applies to RRR'' to ''no.'' Section 63.10(d)(5) describes the reporting requirements for SSM. We will no longer require owners or operators to determine whether actions taken to correct a malfunction are consistent with an SSM plan or report when actions taken during a startup, shutdown, or malfunction were not consistent with an SSM plan, because SSM plans will no longer be required. To replace the General Provisions reporting requirement, the EPA is adding reporting requirements to 40 CFR 63.1516(d). The replacement language differs from the General Provisions requirement in that it eliminates periodic SSM reports as a stand-alone report. We are requiring sources that fail to meet an applicable standard at any time to report the information concerning such events in the semi-annual excess emission report already required under 40 CFR part 63, subpart RRR. The report must contain the emission unit ID, monitor ID, pollutant or parameter monitored, beginning date and time of event, end date and time of the event, cause of the deviation or exceedance, corrective action taken, a list of the affected source or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to estimate the emissions. Examples of such methods would include product-loss calculations, mass balance calculations, measurements when available, or engineering judgment based on known process parameters. The EPA is promulgating this requirement to ensure that there is adequate information to determine compliance, to allow the EPA to determine the severity of the failure to meet an applicable standard, and to provide data that may document how the source met the general duty to minimize emissions during a failure to meet an applicable standard.

D. What other changes have been made to the NESHAP?

This section provides a summary of other changes to the NESHAP. More details and further explanation of these changes are provided in section IV of this preamble and/or in the response to comments document, which is available in the docket for this action. These other changes include the following:

1. Clarification of applicability of rule provisions to area sources. We are finalizing revisions to clarify which operating, monitoring, performance testing, and annual compliance certification requirements apply to area sources.

2. Addition or revision of definitions. We added definitions for bale breaker, capture and collection system, HF, round top furnace, startup, shutdown, tap, and total reactive fluoride flux injection rate. We revised the definitions for aluminum scrap shredder, clean charge, cover flux, group 2 furnace, HCl, residence time, scrap dryer/delacquering/decoating kiln, and SAPU.

3. Revision of provisions to include HF. We have revised 40 CFR 63.1503, 63.1505, 63.1506, 63.1510, 63.1511, 63.1512, 63.1513, 63.1516, and Table 1 of the rule to address HF in the emission standards and in the performance testing, monitoring, and compliance demonstration provisions for group 1 furnaces.

4. Addition of criteria for changing furnace classifications and an allowed frequency of such changes of four times in any 6-month period. We are finalizing requirements for changing furnace classifications in 40 CFR 63.1510, 63.1514, and 63.1517 of the final rule.

5. Revisions to operating requirements. We are finalizing revisions to operating requirements with respect to the following:

• Provisions for controlled group 1 furnaces that will be idled for at least 24 hours in 40 CFR 63.1506(m)(7) and Table 2;

• A requirement for lime injection rate verification in 40 CFR 63.1506(m), 63.1510(i)(4), 63.1512, and Table 3; and

• Alternative compliance options for sweat furnaces in lieu of following the ACGIH Guidelines.

6. Revisions to monitoring requirements. We are finalizing revisions to monitoring requirements with regard to:

• Annual inspections of capture/collection systems in 40 CFR 63.1510(d)(2);

• Flux monitoring in 40 CFR 63.1510(j)(4) and in Table 3 of the rule;

• Bag leak detection system maintenance in 40 CFR 63.1510(f)(1)(ii) and in Table 3;

• Monitoring of sidewell group 1 furnaces in 40 CFR 63.1510(n)(1);

• SAPU compliance with emission factors in 40 CFR 63.1510(t); and

• Compliance options for sweat furnaces in 40 CFR 63.1510(d)(3) as an alternative to the monitoring requirements to conduct annual flow rate measurements using EPA Methods 1 and 2.

As a result of comments on the 2012 proposal, we are not finalizing an amendment to require a 60-day approval period for operation, maintenance and monitoring (OM&M) plans.

7. Revisions to requirements for performance testing/compliance demonstration. We are finalizing

revisions with respect to the following performance testing requirements:

- References to ACGIH guidelines in 40 CFR 63.1502 and 63.1506 and Tables 2 Table 3 for capture and collection systems;
- Section 63.1511(b)(1) and 63.1511(b)(6) to clarify the conditions under which performance tests must be conducted in order to be representative of testing for a ''worst case'' scenario and that multiple tests may be required to characterize all regulated pollutants;
- Section 63.1511(b)(3) to clarify testing requirements for batch processes;
- Section 63.1511(f)(6) to clarify that testing for representative units means that all performance tests must be conducted on the same affected source or emission unit;
- Section 63.1511(b) to allow 180 days to conduct initial performance testing;
- Section 63.1511(g)(5) with respect to altering parameters during performance testing with new feed/charge types; and
- Paragraphs in 40 CFR 63.1512(e) to clarify the requirement to account for unmeasured emissions during performance testing of uncontrolled group 1 furnaces, including:
  - Requirements for installation of temporary hooding for performance testing on uncontrolled group 1 furnaces or, for existing uncontrolled furnaces, use of 80-percent capture efficiency assumption;
  - testing requirements for new uncontrolled furnaces;
  - conditions where installation of temporary hooding that meets ACGIH guidelines is impractical; and
  - procedures to minimize unmeasured emissions during performance testing of uncontrolled furnaces.

8. Revisions to recordkeeping provisions. We are finalizing revisions to 40 CFR 63.1517(b)(4)(ii) with respect to lime injection rates, 40 CFR 63.1517(b)(14) with respect to records related to the annual inspection of capture/collection systems, and 40 CFR 63.1517(b)(19) with respect to records related to startups and shutdowns.

E. What are the effective and compliance dates of the standards?

The revisions to the MACT standards being promulgated in this action are effective on September 18, 2015.

The compliance date for the final amendments listed in 40 CFR 63.1501(d) for existing secondary aluminum production affected sources is March 16, 2016. The compliance date for the final amendments listed in 40 CFR 63.1501(c) for existing affected sources is September 18, 2017. The owner or operator of a new affected source that commences construction or reconstruction after February 14, 2012, must comply with all of the requirements of this subparat by September 18, 2015 or upon startup, whichever is later.

In the 2012 proposal, we proposed that existing affected sources comply with the proposed amendments within 90 days of the publication of the final rule in the **Federal Register**. As described in detail in the 2014 supplemental proposal (79 FR 72906), commenters stated that the proposed 90-day compliance deadline was insufficient for sources to comply with certain provisions of the final rule. These commenters recommended compliance dates of 2 to 3 years due to the need to conduct operational planning, maintenance planning, reprogramming of data acquisition systems, design and installation of hooding equipment, and/or negotiations with permitting authorities to gain performance test plan approvals. The EPA agreed that the proposed 90-day compliance deadline was insufficient. However, we did not agree that sources needed 2 to 3 years to comply with all the requirements. Based on consideration of the comments and further evaluation of the amount of time needed for each of the requirements, the 2014 supplemental proposal included extended compliance periods of 180 days for the revisions listed in 40 CFR 63.1501(d). In this action, we are finalizing compliance deadlines of 180 days after publication of this final rule in the **Federal Register** for the revisions in 40 CFR 63.1501(d). For the amendments related to HF emissions (40 CFR 63.1505(i)(4) and (k)(2)), testing of existing uncontrolled furnaces (40 CFR 63.1512(e)(4), (e)(5), (e)(6) and (e)(7)), and changing furnace classification (40 CFR 63.1514), the EPA agrees that a longer time to comply is appropriate and proposed a compliance period of 2 years in the 2014 supplemental proposal. In this action, we are finalizing a compliance deadline of 2 years after publication of this final rule in the **Federal Register** for the provisions listed in 40 CFR 63.1501(e).

F. What are the requirements for submission of performance test data to the EPA?

As stated in the preamble of the 2012 proposal, the EPA is taking a step to increase the ease and efficiency of data submittal and data accessibility. Specifically, the EPA is requiring owners and operators of secondary aluminum production facilities to submit electronic copies of certain required performance test reports.

As mentioned in the preamble of the proposal, data will be collected by direct computer-to-computer electronic transfer using EPA-provided software. As discussed in the proposal, the EPA-provided software is an electronic performance test report tool called the ERT. The ERT will generate an electronic report package which will be submitted to the Compliance and Emissions Data Reporting Interface (CEDRI) and then archived to the EPA's Central Data Exchange (CDX). A description and instructions for use of the ERT can be found at *http://www.epa.gov/ttn/chief/ert/index.html*, and CEDRI can be accessed through the CDX Web site at *www.epa.gov/cdx*.

The requirement to submit performance test data electronically to the EPA does not create any additional performance testing and will apply only to those performance tests conducted using test methods that are supported by the ERT. A listing of the pollutants and test methods supported by the ERT is available at the ERT Web site. The EPA believes, through this approach, industry will save time in the performance test submittal process. Additionally, this rulemaking benefits industry by cutting back on recordkeeping costs as the performance test reports that are submitted to the EPA using CEDRI are no longer required to be kept in hard copy.

As mentioned in the proposed preamble, state, local, and tribal agencies will benefit from more streamlined and accurate review of performance test data that will be available on the EPA WebFIRE database. The public will also benefit. Having these data publicly available enhances transparency and accountability. For a more thorough discussion of electronic reporting of performance tests using direct computer-to-computer electronic transfer and using EPA-provided software, see the discussion in the preamble of the proposal.

In summary, in addition to supporting regulation development, control strategy development, and other air pollution control activities, having an electronic database populated with performance test data will save industry, state, local, tribal agencies, and the EPA significant time, money, and effort while improving the quality of emission inventories, air quality regulations, and enhancing the public's access to this important information.

G. What materials are being incorporated by reference?

In this final rule, the EPA is including regulatory text that includes incorporation by reference. In accordance with requirements of 1 CFR 51.5, the EPA is incorporating by reference the following documents described in the amendments to 40 CFR 63.14:

- ASTM D7520–13, Standard Test Method for Determining the Opacity of a Plume in an Outdoor Ambient Atmosphere, approved December 1, 2013.
- EPA–625/3–89–016, Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and -Dibenzofurans (CDDs and CDFs) and 1989 Update, March 1989, U.S. Environmental Protection Agency.
- Industrial Ventilation: A Manual of Recommended Practice, 23rd Edition, 1998, Chapter 3, ''Local Exhaust Hoods'' and Chapter 5, ''Exhaust System Design Procedure.'' American Conference of Governmental Industrial Hygienists.
- Industrial Ventilation: A Manual of Recommended Practice for Design, 27th Edition, 2010, American Conference of Governmental Industrial Hygienists.

In the 2014 supplemental proposal, we identified ASTM D7520–09 as an alternative method for the currently required EPA Method 9. Since then, the method has been updated to incorporate specific requirements that we included as add-ons to our broad alternative test method approval of the 2009 version of the ASTM method. We do not expect any concerns changing to the new version because the additional requirements are handled by the vendors of the digital camera/software systems.

The EPA has made, and will continue to make, these documents generally available electronically through *www.regulations.gov* and/or in hard copy at the appropriate EPA office (see the **ADDRESSES** section of this preamble for more information).

IV. What is the rationale for our final decisions and amendments for the Secondary Aluminum Production source category?

For each issue, this section provides a description of what we proposed and what we are finalizing for the issue, the EPA's rationale for the final decisions and amendments, and a summary of key comments and responses. For all comments not discussed in this preamble, comment summaries and the EPA's responses can be found in the comment summary and response document, which is available in the docket.

A. Residual Risk Review for the Secondary Aluminum Production Source Category

1. What did we propose pursuant to CAA section 112(f) for the Secondary Aluminum Production source category?

Pursuant to CAA section 112(f), we conducted a revised residual risk review and presented the results of this review, along with our proposed decisions regarding risk acceptability and AMOS, in the December 8, 2014, supplemental proposal (79 FR 72874). The results of the revised risk assessment are presented briefly below in Table 2 and in more detail in the residual risk document, *Residual Risk Assessment for the Secondary Aluminum Source Category in Support of the 2015 Risk and Technology Review Final Rule,* which is available in the docket for this rulemaking.

a. *Inhalation Risk Assessment Results.* The results of the chronic baseline inhalation cancer risk assessment indicate that, based on estimates of current actual emissions, the maximum individual risk (MIR) posed by the Secondary Aluminum Production source category from major sources and from area sources was less than 1-in-1 million. The estimated cancer incidence was slightly higher for area sources compared to the major sources due to the larger number of area sources nationwide. The total estimated cancer incidence from secondary aluminum production sources from both major and area sources based on actual emission levels was 0.002 excess cancer cases per year, with emissions of D/F, naphthalene, and Polycyclic Aromatic Hydrocarbons (PAH) contributing 48 percent, 31 percent, and 11 percent, respectively, to this cancer incidence. In addition, we note that there are no excess cancer risks greater than or equal to 1-in-1 million as a result of inhalation exposure to actual emissions from this source category over a lifetime. The maximum modeled chronic non-cancer hazard index (HI) target organ-specific HI (TOSHI) value for the source category for both major and area sources based on actual emissions was estimated to be 0.04, with HCl emissions from group 1 furnaces accounting for 99 percent of the HI.

TABLE 2—SECONDARY ALUMINUM PRODUCTION SOURCE CATEGORY INHALATION RISK ASSESSMENT RESULTS

Number of facilities modeled	Maximum individual cancer risk (in 1-million) [a]		Estimated annual cancer incidence (cases/yr) [d]	Estimated population at increased risk of cancer ≥ 1-in-1 million [d]	Maximum chronic non-cancer TOSHI [b]		Worst-case maximum screening acute non-cancer HQ [c]
	Based on actual emissions	Based on allowable emissions			Based on actual emissions level	Based on allowable emissions level	
Major Sources (52)	0.6	4	0.0007	0	0.04	0.1	$HQ_{(REL)}$ = 0.7 (HF). $HQ_{(AEGL1)}$ = 0.4 (HCl).
Area Sources (103)	0.3	1	0.001	0	0.0003	0.001	NA.
Facility-wide (52 Major Sources)	70	NA	0.05	760,000	1	NA	NA.

[a] Estimated maximum individual excess lifetime cancer risk due to HAP emissions from the source category for major sources and D/F emissions from the source category for area sources.

[b] Maximum TOSHI. The target organ with the highest TOSHI for the Secondary Aluminum Production source category for both actual and allowable emissions is the respiratory system.

[c] There is no acute dose-response value for D/F. Thus an acute hazard quotient (HQ) value for area sources was not calculated. The maximum off-site HQ acute value of 0.7 for actuals is driven by emissions of hydrofluoric acid. See section III.A.3 of the 2014 supplemental proposal (79 FR 72885) for explanation of acute dose-response values. Acute assessments are performed based on actual emissions.

[d] These estimates are based upon actual emissions.

When considering MACT-allowable emissions, the inhalation cancer MIR was estimated to be up to 4-in-1 million, driven by emissions of D/F compounds, naphthalene, and PAHs from the scrap dryer/delacquering/decoating kiln. The estimated potential cancer incidence considering allowable emissions for both major and area sources was estimated to be 0.014 excess cancer cases per year, or 1 case every 70 years. Approximately 3,400 people were estimated to have cancer risks greater than or equal to 1-in-1 million considering allowable emissions from secondary aluminum production plants. When considering MACT-allowable emissions, the maximum chronic non-cancer TOSHI value was estimated to be 0.1, driven by allowable emissions of HCl from the group 1 furnaces.

b. *Acute Risk Results.* Our screening analysis for worst-case acute impacts based on actual emissions indicates no pollutants exceeding an HQ value of 1 based upon the REL.

c. *Multipathway Risk Screening Results.* Results of the worst-case Tier 1 screening analysis indicated that 36 of the 52 major sources exceeded the persistent and bio-accumulative HAP (PB–HAP) emission cancer screening rates (based on estimates of actual emissions) for D/F, and 3 of the 52 major sources exceeded the Tier 1 screen value for PAHs. Regarding area sources, 60 of the 103 area sources exceeded the PB–HAP emission cancer screening rates (based on estimates of actual emissions) for D/F. For the compounds and facilities that did not screen out at Tier 1, we conducted a Tier 2 screen. The Tier 2 screen replaces some of the assumptions used in Tier 1 with site-specific data, including the location of fishable lakes and local precipitation, wind direction, and speed. The Tier 2 screen continues to rely on high-end assumptions about consumption of local fish and locally grown or raised foods (adult female angler at 99th percentile consumption for fish for the subsistence fisherman scenario and 90th percentile consumption for locally grown or raised foods for the farmer scenario). It is important to note that, even with the inclusion of some site-specific information in the Tier 2 analysis, the multipathway screening analysis is still a very conservative, health-protective assessment (*e.g.,* upper-bound consumption of local fish and locally grown and/or raised foods). In all likelihood, this analysis will yield results that serve as an upper-bound multipathway risk associated with a facility.

While the screening analysis was not designed to produce a quantitative risk result, the factor by which the emissions exceed the threshold serves as a rough gauge of the ''upper-limit'' risks we would expect from a facility. Thus, for example, if a facility emitted a PB–HAP carcinogen at a level 2 times the screening threshold, we can say with a high degree of confidence that the actual maximum cancer risks will be less than 2-in-1 million. Likewise, if a facility emitted a noncancer PB–HAP at a level 2 times the screening threshold, the maximum noncancer hazard would represent an HQ less than 2. The high degree of confidence comes from the fact that the screens are developed using the very conservative (health-protective) assumptions that we describe above.

Based on the Tier 2 cancer screening analysis, 25 of the 52 major sources and 34 of the 103 area sources emitted D/F above the Tier 2 cancer screening thresholds for the subsistence fisher and farmer scenarios. The individual D/F emissions were all scaled based on their toxicity to 2,3,7,8-tetrachlorodibenzo-p-dioxin and reported as TEQ. The subsistence fisher scenario for the highest risk facilities exceeded the D/F cancer threshold by a factor of 80 for the major sources and by a factor of 70 for the area sources. The Tier 2 analysis also identified 23 of the 52 major sources and 26 of the 103 area sources emitting D/F above the Tier 2 cancer screening thresholds for the subsistence farmer scenario. The highest exceedance of the Tier 2 screen value was 40 for the major sources and 20 for the area sources for the farmer scenario.

We had only one major source emitting PAHs above the Tier 2 cancer screen value with an exceedance of 2 for the farmer scenario. All PAH emissions were scaled based on their toxicity to benzo(a)pyrene and reported as TEQ.

A more refined Tier 3 multipathway screening analysis was conducted for six Tier 2 major source facilities. The six facilities were selected because the Tier 2 cancer screening assessments for these facilities had exceedances greater than or equal to 50 times the screen value for the subsistence fisher scenario. The major sources represented the highest screened cancer risk for multipathway impacts. Therefore, further screening analyses were not performed on the area sources. The Tier 3 screen examined the set of lakes from which the fisher might ingest fish. Any lakes that appeared not to be fishable or not publicly accessible were removed from the assessment, and the screening assessment was repeated. After we made the determination the critical lakes were fishable, we analyzed plume rise data for each of the sites. The Tier 3 screen was conducted only on those HAP that exceeded the Tier 2 screening threshold, which for this assessment were D/F and PAHs. Both of these PB–HAP are carcinogenic. The Tier 3 screen resulted in lowering the maximum exceedance of the screen value for the highest site from 80 to 70. Results for the other sites were all less than 70. The highest exceedance of the Tier 2 cancer screen value of 40 for the farmer scenario was also reduced in the Tier 3 screening assessment to a value of 30 for the major sources within this source category.

Overall, the refined multipathway screening analysis for D/F and PAHs utilizing the Tier 3 screen predicted a potential lifetime cancer risk of 70-in-1 million or lower to the most exposed individual, with D/F emissions from group 1 furnaces handling other than clean charge driving the risk. Cancer risks due to PAH emissions for the maximum exposed individual were less than 1-in-1 million.

The chronic non-cancer HQ was predicted to be below 1 for cadmium compounds and 1 for mercury compounds. For lead, we did not estimate any exceedances of the Primary Lead National Ambient Air Quality Standards (NAAQS).

Further details on the refined multipathway screening analysis can be found in Appendix 8 of the *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule,* which is available in the docket.

d. *Environmental Risk Screening Results.* We conducted an environmental risk screening assessment for the Secondary Aluminum Production source category for the following seven pollutants: PAHs, mercury (methyl mercury and mercuric chloride), cadmium, lead, D/F, HCl, and HF.

Of the seven pollutants included in the environmental risk screen, major sources in this source category emit PAHs, mercuric chloride, cadmium, lead, D/F, HCl, and HF. In the Tier 1 screening analysis for PB–HAP, none of the individual modeled concentrations for any facility in the source category exceeded any of the ecological benchmarks (either the lowest-observed-adverse-effect level (LOAEL) or no observed adverse effects level (NOAEL)) for PAHs, mercuric chloride, cadmium, and D/F. For lead, we did not estimate any exceedances of the Secondary Lead NAAQS. For HCl and HF, the average modeled concentration around each facility (*i.e.,* the average concentration of all off-site data points in the modeling domain) did not exceed any ecological benchmark. In addition, each individual modeled concentration of HCl and HF (*i.e.,* each off-site data point in the modeling domain) was below the ecological benchmarks for all facilities.

Of the seven pollutants included in the environmental risk screen, area sources in this source category are regulated only for D/F. In the Tier 1 screening analysis for D/F, none of the individual modeled concentrations for any facility in the source category exceeded any of the ecological benchmarks (either the LOAEL or NOAEL) for D/F.

e. *Facility-wide Risk Assessment Results.* Considering facility-wide emissions at the 52 major sources, the MIR was estimated to be 70-in-1 million driven by arsenic and nickel emissions, and the chronic non-cancer TOSHI value was calculated to be 1, driven by emissions of cadmium compounds. The above risks were driven by emissions from the potline roof vents at the co-located primary aluminum production operations. The Secondary Aluminum Production source category represents less than 1 percent of the inhalation risks from the facility-wide assessment based upon actual emissions. The risks due to primary aluminum production operations are being addressed in a separate RTR rulemaking for the Primary Aluminum Production source category that EPA plans to finalize later this year.

f. *What demographic groups might benefit from this regulation?* We conducted a proximity analysis during the development of the proposed rule, and that analysis is also being used in support of this final rule. We conclude that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. However, the final rule will provide additional benefits to these demographic groups by improving the compliance, monitoring and implementation of the NESHAP.

The detailed results of the proximity analyses can be found in the *EJ Screening Report for Secondary Aluminum Area Sources and the EJ Screening Report for Secondary Aluminum Major Sources,* which are available in the docket for this rulemaking.

2. How did the risk review change for the Secondary Aluminum Production source category?

No new information was received that would alter the results of the revised risk review presented in support of the 2014 supplemental proposal, so no changes were made.

3. What key comments did we receive on the risk review, and what are our responses?

Several comments were received regarding the revised risk assessment for the Secondary Aluminum Production source category. The following is a summary of some key comments and our responses to those comments. Other comments received and our responses to those comments can be found in the document titled, *National Emission Standards for Hazardous Air Pollutant Emissions: Secondary Aluminum Production Summary of Public Comments and Responses on Proposed Rule (77 FR 8576, February 14, 2012) and Supplemental Proposal (79 FR 72874, December 8, 2014),* which is available in the docket for this action.

Comment: One commenter [5] stated that the EPA should reconsider its finding of acceptable risk and instead find risks unacceptable for the following reasons.

The multipathway risk from D/F emissions: *i.e.*, a lifetime cancer risk of up to 70-in-1 million for the most-exposed individual to emissions via a fish (''fisher'') route of exposure, and an additional cancer risk of up to 30-in-1 million for the most-exposed individual to such emissions from a farm (''farmer'') route of exposure. These exposures add up to 100-in-1 million. The EPA has a policy of adding cancer risks to determine the most-exposed individual's maximum risk. The EPA estimates cancer risks ''as the sum of the risks for each of the carcinogenic HAP'' because ''[s]umming the risks of these individual compounds to obtain the cumulative cancer risks is an approach that was recommended by the EPA's SAB in their 2002 peer review of the EPA's National Air Toxics Assessment.'' 79 FR 72886 and n.7 (citing National Air Toxic Assessment (NATA)—Evaluating the National-scale Air Toxics Assessment 1996 Data—a Science Advisory Board (SAB) Advisory). The Agency has given no valid justification for not recognizing that the maximum cancer risk from multipathway exposure could be as high as 100-in-1 million, sufficient for the EPA to find risk unacceptable. Furthermore, the EPA has recognized that the inhalation-based cancer risk could be as high as 4 (based on allowable emissions), or 0.6 (based on so-called ''actual'' emissions). Adding this risk (whether 0.6 or 4) to 100-in-1 million would exceed the EPA's benchmark of 100-in-1 million. The EPA has provided no valid basis for not adding inhalation and multipathway cancer risks. The EPA should look at the whole picture of cancer risk, in view of its additive policy for cancer. Thus, together these data points show that the EPA should find total cancer risk from this source category to be unacceptable.

Moreover, the EPA's multipathway risk does not evaluate all persistent and/or bioaccumulative pollutants, and, thus, its multipathway risk assessment is likely underestimating these risks. The EPA should evaluate all persistent, bioaccumulative, and toxics (PBTs) emitted by the secondary aluminum source category, including all HAP metals emitted (such as arsenic and nickel).

In addition, if inhalation-based cancer risk is more than 3 times as high from allowable emissions (as from so-called ''actual'' emissions), then multipathway-based cancer risk, which the EPA has not evaluated based on allowable emissions, is also likely to be more than 3 times as high, or at least higher than the numbers the EPA found. Thus, the fish-based risk could be as high as 210-in-1 million, and the farm-based risk could be as high as 90-in-1 million; together, the maximum multipathway cancer risk the EPA should be considering for the most-exposed individual is 300-in-1 million. The EPA has given no valid justification for not considering allowable emissions-based risk from multipathway exposure. Doing so would lead the Agency to find cancer risk from multipathway exposure to be well above 100-in-1 million.

The commenter stated that the above analysis shows why, based on cancer risk alone, the EPA should find secondary aluminum plants' current risk is unacceptable and, thus, set standards to reduce these plants' D/F and other cancer-causing emissions.

The commenter stated that the EPA also found other health risks, including chronic non-cancer and acute risks, which only add more evidence of the harm the most-exposed individual faces from this source category. The commenter stated that, for example, the acute HQ from HF is 0.7, and from HCl is 0.4, which, added together, to consider the maximum acute risk, would be 1.1, above the level at which the EPA recognizes harm can occur. The commenter stated that the EPA has not added these risks, nor given any valid justification for not doing so, even though if there is an acute spike in emissions, it is just as likely that the most-exposed person would breathe various pollutants that may spike together—*i.e.*, HCl, HF, and other pollutants, not just each pollutant individually. The commenter stated that the EPA's acute HQ is likely too low.

The commenter stated that it is also unclear whether the EPA has used the most current, most protective D/F reference doses and concentrations, including the 2012 D/F value of 7×10^{-10} milligram (mg)/kilogram (kg)-day, for chronic oral exposure; the EPA should confirm that it has used the best

[5] In summarizing the key comments, we have indicated when a comment was submitted on the 2014 supplemental proposal. Unless otherwise noted, the remaining comments were submitted on the 2012 proposed rule.

available scientific information on reference values. The commenter stated that the EPA should follow the best available scientific approach to risk assessment, as shown in California's risk assessment guidance manual and supporting scientific documents.

Response: We disagree with the commenter's arguments for finding risks to be unacceptable and have combined risk to the extent that it is appropriate to do so. We explain below and in the Residual Risk Assessment document, which is available in the docket for this rulemaking, why we do not sum the risk results from the fisher and farmer scenarios in our multipathway analysis and why we do not combine the risk values from our inhalation assessment with those of the multipathway analysis. We also explain the scope of our multipathway analysis in terms of the pollutants, the source of their dose-response values, and the emission levels. In addition, we explain below why we do not use a TOSHI approach for acute analyses. (See also the *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule*.)

In the multipathway screening assessment, we did not sum the risk results of the fisher and farmer scenarios. The modeling approach used for this analysis constructs two different exposure scenarios, which serves as a conservative estimate of potential risks to the most-exposed receptor in each scenario. Based on the information and assumptions in the assessment, it is highly unlikely that the most-exposed farmer is the same person as the most-exposed fisher, therefore, it is not reasonable to add risk results from these two exposure scenarios. (See Appendix 5 and Section 2.5 of the *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule*.)

We disagree with the commenter's statement that we should combine the results of our inhalation and multipathway assessments for this source category. We determined that it would be inappropriate to do so based on the differences in the design and results of the two types of assessments, as well as the highly conservative nature of the multipathway assessment. First, the screening scenario is a hypothetical scenario, and, due to the theoretical construct of the screening model, exceedances of the thresholds are not directly translatable into, or additive with, estimates of risk or HQ for these facilities. The result of the multipathway screen is number representing an exceedance of a benchmark, which is a ratio, and the results of a cancer risk assessment is a mathematical probability (*i.e.,* increased risk of cancer due to exposure to the HAP emissions from the source category). It is not mathematically appropriate or consistent to add them together. Second, the multipathway risk assessment was a screening-level assessment and not a full risk assessment. The screening assessment used highly conservative assumptions designed to ensure that facilities with results below the screening threshold values did not have the potential for multipathway impacts of concern. The results of the multipathway screen represent a high-end estimate of what the multipathway risk or hazard may be. For example, an exceedance of 2 for a non-carcinogen can be interpreted to mean that we have high confidence that the hazard would be less than 2. Similarly, an exceedance of 30 for a carcinogen means that we have high confidence that the risk is lower than 30-in-1 million. Our confidence comes from the conservative, health-protective assumptions that are in the multipathway screens: We choose inputs from the upper end of the range of possible values for the influential parameters used in the screens; and we assume that the exposed individual exhibits ingestion behavior that would lead to a high total multipathway exposure. We conclude that it is not appropriate to sum the risk results from the chronic inhalation assessment and the screening multipathway assessment. In addition, it is highly unlikely that the same receptor has the maximum results in both assessments. In other words, it is unlikely that the person with the highest chronic inhalation cancer risk is also the same person with the highest individual multipathway cancer risk because it is unlikely that the same receptor has the maximum exposure and risk in both assessments.

We currently do not have screening values for some PB–HAP, but we disagree that the multipathway assessment is inadequate because it did not include ''all HAP metals emitted (such as arsenic and nickel).'' We developed the current PB–HAP list considering all available information on persistence and bioaccumulation (see *http://www2.epa.gov/fera/air-toxics-risk-assessment-reference-library-volumes-1-3,* specifically Volume 1, Appendix D). (The Air Toxics Risk Assessment Reference Library presents the decision process by which the PB–HAP were selected and provides information on the fundamental principles of risk-based assessment for air toxics and how to apply those principles.) In developing the list, we considered HAP identified as PB–HAP by other EPA Program Offices (*e.g.,* the Great Waters Program), as well as information from the PBT profiler (see *http://www.pbtprofiler.net/*). Considering this list was peer-reviewed by the SAB and found to be acceptable, we believe it to be reasonable for use in risk assessments for the RTR program. Based on these sources and the limited available information on the persistence and bioaccumulation of other HAP, we do not believe that the potential for multipathway risk from other HAP not on the list, such as other metal HAP including arsenic and nickel, rises to the level of the PB–HAP on the list. However, in the future, we may add more pollutants to the multipathway analysis if we determine it is appropriate to do so.

Regarding the commenter's assertion that we did not base the multipathway risk assessment on allowable emissions, we believe it is reasonable for the multipathway risk assessment to be based on actual emissions for this source category, and not the allowable level of emissions that facilities are permitted to emit. The uncertainties associated with the multipathway screen along with uncertainties in the allowable emissions estimates, which are highly variable for this source category, would make a multipathway risk assessment based on allowable emissions highly uncertain. Such an assessment would be too uncertain to support a regulatory decision. Many of the best-performing (based on actual emissions) sources have allowable emissions that are orders of magnitude greater than their actual emissions, and those facilities could not reasonably be expected to operate in such a manner that would result in emissions that even approach our estimates of allowable emissions.

The commenter also argues for summing acute hazard quotients from different HAP to assess acute non-cancer risk. We do not sum results of the acute noncancer inhalation assessment to create a combined acute risk number that would represent the total acute risk for all pollutants that act in a similar way on the same organ system or systems (analogous to the chronic TOSHI) because the worst-case acute screen is already a conservative scenario. The acute screening scenario assumes worst-case meteorology, peak emissions for all emission points occurring concurrently and an individual being located at the site of maximum concentration for an hour. Thus, as noted in the risk assessment report available in the docket, ''because of the conservative nature of the acute inhalation screening and the variable nature of emissions and potential exposures, acute impacts were screened on an individual pollutant basis, not using the TOSHI approach.''

The dose-response values used in the risk assessment, including those for D/F, are based on the current peer reviewed Integrated Risk Information System (IRIS) values, as well as other similarly peer-reviewed values. Our approach, which uses conservative tools and assumptions, ensures that our decisions are appropriately health protective and environmentally protective. The approach for selecting appropriate health benchmark values, in general, places greater weight on the EPA derived health benchmarks than those from other agencies (see *http://www.epa.gov/ttn/atw/nata1999/99pdfs/healtheffectsinfo.pdf*). This approach has been endorsed by the SAB. The SAB further recommended that the EPA scrutinize values that emerge as drivers of risk assessment results and the Agency has incorporated this recommendation into the risk assessment process. This may result in the EPA determining that it is more appropriate to use a peer-reviewed dose-response value from another agency even if an IRIS value exists.

We generally draw no bright lines of acceptability regarding cancer or noncancer risks from source category HAP emissions. It is always important to consider the specific uncertainties of the emissions and health effects information regarding the source category in question when deciding exactly what level of cancer and noncancer risk should be considered acceptable. In addition, the source category-specific decision of what constitutes an acceptable level of risk should be a holistic one; that is, it should simultaneously consider all potential health impacts—chronic and acute, cancer and noncancer, and multipathway—along with their uncertainties, when determining the acceptable level of source category risk. The Benzene NESHAP decision framework of 1989 acknowledged this; such flexibility is imperative, because new information relevant to the question of risk acceptability is being developed all the time, and the accuracy and uncertainty of each piece of information must be considered in a weight-of-evidence approach for each decision. This relevant body of information is growing fast (and will continue to do so), necessitating a flexible weight-of-evidence approach that acknowledges both complexity and uncertainty in the simplest and most transparent way possible. While this challenge is formidable, it is nonetheless the goal of the EPA's RTR decision-making, and it is the goal of the risk assessment to provide the information to support the decision-making process.

Comment: One commenter recommended that the EPA consider potential or allowable emissions, rather than actual emissions, as much as possible in evaluating residual risk. The commenter stated that because facility emissions could increase over time for a variety of reasons, and with them the associated impacts, the use of potential or allowable emissions is more appropriate; an analysis based on actual emissions from a single point in time could underestimate the risk. The commenter stated that the major source HAP thresholds are based on maximum potential-to-emit, as opposed to actual emissions, and air agencies issue permits based on potential emissions. The commenter stated that limiting the scope of a risk evaluation to actual emissions would be inconsistent with the applicability section of 40 CFR part 63 rules. The commenter stated that they were pleased that the EPA used allowable emissions in parts of the rulemaking, but were concerned that the EPA continues to use actual emissions in other parts of its assessment. The commenter encouraged the agency to use allowable emissions in the future, including in assessing acute health risks.

One commenter agreed that the EPA appropriately concluded that secondary aluminum production does not pose risks warranting standard revision under section 112(f) of the CAA. The commenter noted that under the proposal, the EPA would find that the risks from the emission of HAP from sources in the Secondary Aluminum Production source category are acceptable and that the current MACT standards provide an AMOS to protect public health and prevent an adverse environmental effect. The commenter stated that to determine these findings, the EPA utilized both MACT-allowable and actual emissions data for its risk analysis. The commenter supported the findings of acceptable risk and an AMOS, but noted that the use of MACT-allowable emissions in the risk assessment process is not required for such a finding.

The commenter indicated that the use of actual emissions in risk assessments is more accurate than MACT-allowable emissions and is supported by the language of CAA section 112(f). The EPA is required to promulgate emission standards under CAA section 112(f) if ''excess cancer risks to the individual most exposed to emissions from a source'' are 1 in 1 million or greater. The commenter states that the statute does not use words such as ''maximum allowable,'' or ''potential.'' Rather, the statute limits the risk review to consider the risks to the individual most exposed to the emissions from a particular source. The commenter concluded that it is clear from the wording of the statute that Congress intended the EPA to estimate risk based on the actual exposure. The commenter also stated that MACT-allowable emissions represent a hypothetical, worst-case, emissions level to which an individual is unlikely to ever be exposed, especially given the already conservative assumptions inherent in the risk models. The commenter claimed that basing emission standards on worst-case scenarios can lead to imposition of costly and unnecessary controls which do little to reduce actual risk. The commenter claimed that, given that the EPA has actual emissions data from secondary aluminum production facilities, it should base its risk assessments on this best available data.

In contrast, another commenter stated that they support the findings of acceptable risk, AMOS; and they also support the EPA's revisions to the allowable emissions calculation method that uses the actual amount of charge; however, the use of MACT-allowable emissions in the risk assessment process is not required for such a finding. The commenter stated that due to process variability, sources cannot emit HAP at MACT-allowable levels at all times and remain in compliance and it is likely that sources may reduce their emissions due to state or local rules, or for reasons other than compliance. The commenter stated that basing emission standards on worst-case scenarios can lead to imposition of costly and unnecessary controls, which do little to reduce actual risk. The commenter stated that the EPA points to two previous actions in which the EPA noted that the use of allowable emissions was reasonable; however, in both of these actions, the EPA used actual emissions because they were the most accurate data available. Because the EPA has actual emissions data from secondary aluminum production facilities, the commenter asserted that it should base its risk assessments on these data. The commenter further stated that, to the extent that the EPA continues to calculate allowable emissions, they support the EPA's use of actual charge rates, which reflect real production rates and should result in more accurate allowable emissions totals than maximum production capacity.

Response: Consistent with previous risk assessments, the EPA considers both allowable and actual emissions in assessing chronic exposure and risk under CAA section 112(f)(2). See, *e.g.,* National Emission Standards for Coke Oven Batteries (70 FR 19998–19999, April 15, 2005); proposed and final National Emission Standards for Organic Hazardous Air Pollutants from the Synthetic Organic Chemical Manufacturing Industry (71 FR 34428, June 14, 2006, and 71 FR 76603, December 21, 2006). This approach is both reasonable and consistent with the flexibility inherent in the Benzene NESHAP framework for assessing acceptable risk and AMOS. As a general matter, modeling allowable emission levels is inherently reasonable since this reflects the maximum level sources could emit and still comply with national emission standards. But it is also reasonable to consider actual emissions, where such data are available, in the acceptable risk and AMOS analyses. See National Emission Standards for Coke Oven Batteries, 70 FR 19992, 19998 (April 15, 2005). The risk assessment for the Secondary Aluminum Production source category was conducted using actual and allowable emissions, and all of the results were considered in determining risk acceptability and AMOS. We agree with the commenter that it is appropriate to estimate allowable emissions using production rates that reflect current operations rather than using maximum production capacity. See *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule.*

One commenter claims that limiting our review to actual emissions would be inconsistent with the applicability section of 40 CFR part 63 rules. As explained above and in the 2014 supplemental proposal, however, we did not limit our review to actual emissions, but rather considered actual emissions and allowable emissions, as appropriate, in particular portions of the risk assessment. The commenter also urges the Agency to rely on allowable emissions for the purpose of our acute screening assessment. We did not rely on allowable emissions for the acute screening assessment due to the conservative assumptions used to gauge worst-case potential acute health effects. The conservative assumptions built into the acute health risk screening analysis include: (1) Use of peak 1-hour emissions that are on average 10 times the annual average 1-hour emission rates; (2) that all emission points experience peak emissions concurrently; (3) worst-case meteorology (from 1 year of local meteorology); and (4) that a person is located downwind at the point of maximum impact during this same 1hour period. Thus, performing an acute screen based on allowable emissions would be overly conservative and, at best, of questionable utility to decision makers.

We also note that our use of allowable emission levels in the risk assessments in this rulemaking did not result in revising the previously established standards due to risk concerns. Therefore, our consideration of allowable emissions in the risk assessments did not result in regulatory decisions that affect any facilities.

Comment: One commenter on the supplemental proposal stated that at least nine secondary aluminum facilities have co-located primary aluminum operations, and for both source categories the EPA found that the facility-wide MIR is 70-in-1 million, driven by arsenic, nickel, and hexavalent chromium, and that the TOSHI (chronic non-cancer risk) is 1, driven by cadmium. The commenter stated that both numbers appear to consider only inhalation risk and must be viewed in context, as scientists have directed the EPA to do. The commenter stated that, if considered in combination with the high secondary aluminum multipathway risk, and with the high inhalation and multipathway risks for primary aluminum, the facility-wide cancer risk provides additional evidence that risks from both source categories are unacceptable, because the most-exposed person's full amount of risk is the combined amount from the co-located primary and secondary aluminum, not just each source category separately. The commenter stated that it would be unlawful and arbitrary to consider each type of risk separately, when people near both sources are exposed to both kinds of risk at the same time, and, thus, face a higher overall amount of risk.

The commenter stated that the EPA has offered and can offer no valid justification for not finding risk from both source categories (including primary aluminum prebake, and secondary aluminum) to be unacceptable based on the co-located and combined risks. The commenter stated that the EPA may not lawfully ignore the full picture of risk that its combined rulemakings show is present for people exposed simultaneously to both source categories at the same facility.

The commenter further stated that, because the EPA only assessed facility-wide risks based on so-called ''actual'' emissions, the facility-wide risk number could be at least 1.5 to 3 times higher. The commenter bases this assertion on the EPA's recognition that allowable emissions from primary aluminum are about 1.5 to 1.9 times higher than actual emissions and the fact that allowable emissions from secondary aluminum are at least 3 times higher than actual emissions.

The commenter stated that it is important that EPA is evaluating facility-wide risk from sources in multiple categories that are co-located and that EPA needs to consider the results of such facility-wide analyses when determining if stronger standards should be established for these sources. The commenter stated that this rulemaking is an important opportunity for the EPA to recognize the need to act based on data showing significant combined and cumulative risks and impacts at the facility-wide level. The commenter stated that the EPA is also required to do so to meet its CAA section 7412(f)(2) duties.

The commenter stated that the EPA also should be evaluating the cumulative risks from all nearby toxics sources in multiple source categories, not looking only at multiple sources in the same category, and different sources at the same facility. The commenter stated that the EPA has said it recognizes the need to put risk in context, but still has not even attempted to evaluate the bigger picture of health risks by looking at all nearby sources (from various source categories, including those collocated and those not collocated). According to the commenter, in doing so would likely lead to recognizing that the individual most-exposed to each of these source categories is also experiencing significant risks from other sources, providing even more evidence as to why the EPA should reduce risks from the primary and secondary aluminum source categories.

Response: With regard to facility-wide assessments, we conducted such assessments for all 52 major sources in the source category, including the nine secondary aluminum production facilities co-located with primary aluminum reduction plants. The methods and results of the facility-wide risk assessment, in addition to the inhalation and multipathway analyses for facilities in the source category, are discussed above and in the risk assessment document for the 2014 supplemental proposal, as well as in the risk assessment document for the 2015 final rule. Specifically, we modeled whole-facility inhalation risks for both chronic cancer and non-cancer impacts to understand the risk contribution of the sources within the secondary aluminum source category to facility-wide risks. The individual cancer risks for the source category were aggregated for all carcinogens. In assessing noncancer hazard from chronic exposures for pollutants that have similar modes of action or (where this information is absent) that affect the same target organ, we aggregated the HQ. This process creates, for each target organ, a TOSHI, defined as the sum of hazard quotients for individual HAP that affect the same organ or organ system. All TOSHI calculations presented here were based exclusively on effects occurring at the ''critical dose'' (*i.e.*, the lowest dose that produces adverse health effects). Whole facility risks were estimated based on emissions data obtained from facilities.

The commenter stated that the EPA must find the risks unacceptable based on the whole-facility risks from co-located primary and secondary aluminum operations. The EPA does not typically include whole-facility assessments in the CAA section 112(f) acceptability determination for a source category. Reasons for this include the fact that emissions and source characterization data are usually not of the same vintage and quality for all source categories that are on the same site, and thus the results of the whole-facility assessment are generally not appropriate to include in the regulatory decisions regarding acceptability. However, in this rare case, we are developing the risk assessments for primary and secondary aluminum production at the same time. The data are generally of the same vintage and we have actual emissions data and source characterization data for both source categories. In response to the comment, we refer to the facility-wide risk assessment, which included the nine facilities with co-located primary and secondary aluminum operations. As discussed above and shown in Table 2, for the facility with the highest risk from inhalation, the facility-wide MIR for cancer from actual emissions is 70-in-1 million. The facility-wide non-cancer hazard is 1. The highest facility-wide exceedance of the multipathway screen is 70. There was no facility-wide exceedance of a noncancer threshold in the multipathway screen. Considering these facility-wide results as part of the acceptability determination does not change our determination that the risks are acceptable for the secondary aluminum source category. We note that while the incorporation of additional background concentrations from the environment in our risk assessments (including those from mobile sources and other industrial and area sources) could be technically challenging, they are neither mandated nor barred from our analysis. In developing the decision framework in the Benzene NESHAP used for making residual risk decisions, the EPA rejected approaches that would have mandated consideration of background levels of pollution in assessing the acceptability of risk, concluding that comparison of acceptable risk should not be associated with levels in polluted urban air (54 FR 38044, 38061, September 14, 1989). Background levels (including natural background) are not barred from the EPA's AMOS analysis, and the EPA may consider them, as appropriate and as available, along with other factors, such as cost and technical feasibility, in the second step of its CAA section 112(f) analysis. As discussed in the 2014 supplemental proposal, the risk assessment for this source category did not include background contributions (that may reflect emissions that are from outside the source category and from other than co-located sources) because the available data are of insufficient quality upon which to base a meaningful analysis.

The commenter is correct that we based our facility-wide risk assessment on actual emission rather than on estimated allowable emissions. Because the facility-wide allowable emissions estimates have not been subjected to the same level of scrutiny, quality assurance, and technical evaluation as the actual emissions estimates from the source category, a facility-wide risk assessment based on allowable emissions estimates would be too uncertain to support a regulatory decision.

4. What is the rationale for our final approach and final decisions for the risk review?

As discussed above and in the 2014 supplemental proposal, after considering health risk information and other factors, including uncertainties, we determined that the risks from the Secondary Aluminum Production source category are acceptable and the current standards provide an AMOS to protect public health. In summary, our revised risk assessment indicates cancer risks below the presumptive limit of acceptability and non-cancer results indicating minimal likelihood of adverse health effects, and we identified no control technologies or other measures that would be cost effective in further reducing risks (or potential risks). In particular, we did not identify any cost-effective approaches to further reduce D/F emissions and multipathway risk beyond what is already being achieved by the current NESHAP.

B. Technology Review for the Secondary Aluminum Production Source Category

1. What did we propose pursuant to CAA section 112(d)(6) for the Secondary Aluminum Production source category?

Pursuant to CAA section 112(d)(6), we conducted a technology review to identify and evaluate developments in practices, processes and control technologies for the Secondary Aluminum Production source category, as described in the 2012 proposal. Details of the technology review and its findings are available in the memoranda, *Draft Technology Review for the Secondary Aluminum Production Source Category* (Docket item EPA–HQ–OAR–2010–0544–0144) and *Draft Technical Support Document for the Secondary Aluminum Production Source Category* (Docket item EPA–HQ–OAR–2010–0544–0152). The typical controls used to minimize emissions at secondary aluminum facilities include fabric filters for control of PM from aluminum scrap shredders; afterburners for control of THC and D/F from thermal chip dryers; afterburners plus lime-injected fabric filters for control of PM, HCl, THC and D/F from scrap dryers/delacquering kilns/decoating kilns; afterburners for control of D/F from sweat furnaces; fabric filters for control of PM from dross-only furnaces and rotary dross coolers; lime-injected fabric filters for control of PM and HCl from in-line fluxers; and lime-injected fabric filters for control of PM, HCl and D/F from group 1 furnaces. In our review of technology, we determined that there have been some developments in practices, processes or control technologies, but we did not identify any of the developments as cost-effective. We stated in the 2012 proposal that the technology review did not warrant any amendments to Subpart RRR.

Following the 2012 proposal, no public comments were received to alter the conclusions of our technology review for the Secondary Aluminum Production source category. In the 2014 supplemental proposal, we proposed that the technology review findings from the 2012 proposal were still valid and that the EPA was not aware of any changes in technology development since the 2012 proposal. See *Supplemental Proposal Technology Review for the Secondary Aluminum Production Source Category* and *Supplemental Proposal Technical Support Document for the Secondary Aluminum Production Source Category,* both available in the docket for this rulemaking. Based on our findings, no rule amendments based on the technology review were proposed.

2. How did the technology review change for the Secondary Aluminum Production source category?

Following the 2014 supplemental proposal, we received no comments and identified no information to alter our findings and conclusions in the technology review for the Secondary Aluminum Production source category. We did, however, update certain information on capture efficiency and costs. Updated information can be found in *Technical Support Document for the Secondary Aluminum Production Source Category Final Rule,* which is available in the docket for this rulemaking.

3. What key comments did we receive on the technology review, and what are our responses?

Comment: In a comment on the supplemental proposal, commenter 0301 stated that this source category is listed for regulation under 42 U.S.C. 7412(c)(6) as a result of its dioxin/furan emissions and that EPA has proposed to rely on the Secondary Aluminum standards to meet its section 7412(c)(6) responsibility, in part, for dioxin {Commenter's footnote: EPA, Completion of Requirement to Promulgate Emissions Standards, 79 FR 74,656, 74,664 tbl.1 (Dec. 16, 2014)}. The commenter stated that in this rulemaking, EPA has proposed not to update these emission standards to strengthen protection from dioxins/furans, even though it recognizes that developments in practices, processes, and control technologies have occurred that could reduce HAP emissions, such as activated carbon injection. The commenter stated that as explained in their 2012 comments on primary aluminum, when there are ''developments'' under section 7412(d)(6), EPA must promulgate revised standards. The commenter stated that revised emission standards—like any other section 7412(d) standards—must satisfy the floor and beyond-the-floor requirements of section 7412(d)(2)–(3), which state that they apply explicitly to ''emissions standards promulgated under this subsection,'' *i.e.*, under section 7412(d). The commenter stated that EPA must set revised standards that are at least as stringent as the emission limitation achieved by the relevant best-performing sources under section 7412(d)(3), and must assure the maximum achievable degree of emission reduction at the beyond-the-floor stage, as required by section 7412(d)(2).

Response: The original MACT standards for dioxins/furans for the secondary aluminum industry helped to satisfy the EPA's obligations under 42 U.S.C. 7412(c)(6), and the subsequent technology reviews for the source category has no bearing on our 112(c)(6) finding.

The commenter is incorrect in stating that there have been developments in practices, processes, and control technologies that would warrant revisions to the standards. As we stated in the preamble to the supplemental proposal (79 FR at 72901), there have been no developments in technology in this industry that warrant any changes to subpart RRR. The commenter's identification of activated carbon as a new control technology for this industry is also not correct as it has been available to the industry since before the 2000 final rule. Furthermore, as part of the technology review contained in the 2014 supplemental proposal (see 79 FR at 72901), we performed an analysis to evaluate lowering the D/F emissions limit from 15 to 10 μg TEQ/Mg for group 1 furnaces processing other than clean charge at all facilities. The analysis performed for the supplemental proposal assumed that furnaces above 10 μg TEQ/mg added activated carbon injection to achieve exactly the 10 ug TEQ/Mg limit. That analysis has been updated and assumes that all furnaces with emissions above 10 μg TEQ/Mg that add activated carbon injection achieve an 85-percent reduction in D/F emissions. The updated analysis is available in *Technical Support Document for the Secondary Aluminum Production Source Category Final Rule,* which is available in the docket for this rulemaking.

We disagree with the comments suggesting that the EPA must recalculate MACT floors and conduct beyond-the floor analyses under CAA section 112(d)(2)–(3) as part of the section 112(d)(6) review. As explained in a prior RTR rulemaking, the EPA does not read 112(d)(6) as requiring a reanalysis or recalculation of MACT floors. See National Emission Standards for Coke Oven Batteries (70 FR 19998–19999, April 15, 2005). We read section 112(d)(6) as providing the EPA with substantial latitude in weighing a variety of factors and arriving at an appropriate balance in considering revisions to standards promulgated under section 112(d)(2) & (3). Nothing in section 112(d)(6) expressly or implicitly requires that EPA recalculate the MACT floor as part of the section 112(d)(6) review. This position has been upheld by the court. *NRDC* v. *EPA*, 529 F.3d 1077, 1084 (D.C. Cir. 2008). We disagree with the commenters that the court's decision hinged on the fact that for the rulemaking at issue we had not identified any developments in practices, processes and control technologies under CAA section 112(d)(6). Rather, the court first states ''[w]e do not think the words 'review and revise as necessary' can be construed reasonably as imposing'' an obligation to completely recalculate maximum achievable control technology. *Id*.

In another comment on the supplemental proposal, one commenter stated that they concur with the Agency's determination that there have been no new developments in practices, processes or control technologies that are applicable to the secondary aluminum production source category that would warrant revisions to the NESHAP.

4. What is the rationale for our final approach for the technology review?

As discussed above and in the 2012 and 2014 proposals, we determined that there have been some developments in practices, processes or control technologies, but we concluded that the technology developments did not warrant any changes to Subpart RRR.

C. Testing of Group 1 Furnaces That Do Not Have Add-On Pollution Control Devices

1. What did we propose related to testing of uncontrolled group 1 furnaces?

In the 2012 proposal, to clarify how furnaces not equipped with an add-on air pollution control device and associated capture and collection system are to be tested for compliance, we proposed compliance alternatives addressing capture and collection of emissions for uncontrolled furnaces during performance testing. Specifically, we proposed that an owner or operator with an uncontrolled furnace could either temporarily install hooding that meets ACGIH guidelines for the duration of the testing or, for an existing uncontrolled furnace, assume 67-percent capture efficiency for furnace exhaust (*i.e.,* multiply measured emissions by 1.5 to account for the uncollected emissions) without installing temporary hooding. As proposed, if the source uses the 67-percent capture efficiency assumption but fails to demonstrate compliance with the emission standard, the source would have to retest using ACGIH hooding or may petition the appropriate authority (permitting authority for major sources or the Administrator for area sources) that such hoods are impractical for the source and propose alternative testing procedures that will minimize unmeasured emissions. We proposed that the retesting must occur within 90 days.

Based on comments received on the 2012 proposal and our consideration of specific testing scenarios and types of uncontrolled furnaces, we proposed revised requirements for the testing of uncontrolled furnaces in the 2014 supplemental proposal. We proposed that if a source uses the 67-percent capture efficiency assumption but fails to demonstrate compliance, then they must retest using ACGIH hooding within 180 days, or the source may petition the appropriate authority within 180 days that such hoods are impractical and propose alternative testing procedures that will minimize unmeasured emissions. In the supplemental proposal, we also proposed conditions that would be considered impractical to install temporary ACGIH hooding and alternative procedures to minimize unmeasured emissions during testing.

Based on comments received on the 2012 proposal, the 2014 supplemental proposal also contained a provision to exclude existing round top furnaces from the proposed requirement to install temporary ACGIH hooding or to use a 67-percent capture efficiency assumption, as well as the proposed option to submit a petition of impracticality. Instead, we proposed that round top furnaces must be operated to minimize unmeasured emissions during testing.

In response to commenters' requests, we proposed example procedures to minimize unmeasured emissions during testing and amendments to clarify in what circumstances installation of temporary capture hoods for testing would be considered impractical.

2. What changed since proposal related to testing of uncontrolled group 1 furnaces?

Based on our consideration of comments and additional information received following the 2014 supplemental proposal, the following changes have been made in the final rule:

- If a facility owner or operator knows in advance that installing ACGIH hoods for testing is not practical, the facility owner or operator may petition the appropriate authority at least 180 days in advance for approval of plans to use alternative testing procedures that will minimize unmeasured emissions during testing.
- Reconstructed round top furnaces are exempt from the testing requirements in 40 CFR 63.1512(e)(4)(i) and (ii), and (iii).
- Additional methods of minimizing unmeasured emissions during testing of uncontrolled group 1 furnaces are added to 40 CFR 63.1512(e)(7) including the use of one or more fans positioned to direct air flow into an open furnace door, and the use of a smaller but representative charge added to the furnace at one time and conducting the test without additional charge.
- We have revised the capture efficiency assumption to 80 percent.

3. What key comments did we receive related to testing of uncontrolled group 1 furnaces?

Comment: One commenter stated that the EPA should not impose a requirement for group 1 furnaces without add-on air pollution control devices (APCD) to construct hoods for performance tests or be subject to a 33-percent reduction in allowed emissions. The commenter asserted that the EPA improperly characterizes this burdensome proposed requirement as a revision to the NESHAP to reportedly ''correct and clarify provisions in the rule.''

One commenter stated that the EPA has provided no information to demonstrate that the proposed requirement for uncontrolled group 1 furnaces is warranted or is consistent with requirements for developing NESHAP. The commenter is concerned that the only support for the proposed hooding requirement that the EPA has provided in the docket is a summary of two stack tests conducted at a single facility. The commenter states that these tests show a large degree of variability between the two tests and for different chemical parameters within each test. The commenter argued that the EPA has provided no information to demonstrate that these tests are indicative of operations throughout the Secondary Aluminum Production source category.

According to the commenter, the information that the EPA provided in the Technical Support Document indicates that the EPA may not have analyzed an appropriate operation to establish regulatory requirements. The commenter observed that if, as indicated in the Technical Support Document, the canopy hood was sampled for over 3 hours because there were emissions to be captured by it, the charge door must have been open for more than 3 hours during the melt cycle. The commenter stated that this scenario does not represent a conventional melting operation.

The commenter presented further concerns that the Technical Support Document states that the test cycle time in the September 5, 2007, test report ''could be a mistake'' and that the testing reported on September 5, 2007, may be ''flawed.'' The commenter noted a wide variation of capture efficiencies for D/F and questioned the EPA's proposal to apply 67-percent capture efficiency across all parameters and all facilities. The commenter claimed that it is unreasonable to apply capture efficiency based on PM or HCl to area sources when area sources are regulated only for D/F.

The commenter stated that the EPA placed the test reports discussed in the RTI Technical Support Document in the docket a month after the proposed rule was published in the **Federal Register**, which reduced the time reviewers had for comment. The commenter had the following concerns about the test reports:

- There is not sufficient information to understand how the furnaces are configured or operated, including how the hood was constructed or placed, and when or for how long the door(s) were left open;
- The hood draft volumes were large compared to furnace stack gas flow volumes, and the capture measured during the tests may not be a good measure of fugitive emissions that would occur in the absence of an induced draft hood;
- The stack temperatures also appear to be low, possibly due to dilution air being drawn into the stack duct prior to the sampling point, which could mean that actual combustion gas flowing from the furnace are much lower than reported at the stack, and the ratio of hood flow volume is much higher than that calculated in the Technical Support Document;
- No production numbers are provided so it is not possible to determine if the furnaces were operating in compliance with the NESHAP requirements; and
- The EPA has provided no indication that they attempted to determine the representativeness of the tests.

One commenter stated that fugitive emissions are minor from a well operated group 1 furnace without add-on controls, as door openings and top removals are kept at a minimum to conserve energy and burners are generally kept at reduced firing rates when furnaces are opened. The commenter stated that the 67-percent capture assumption that the EPA drew does not seem reasonable based on the commenter's observations.

The commenter emphasized that emissions from round top furnaces are negligible during periods when the top is off and burners are on low fire. The commenter stated that these furnaces would be placed at a competitive disadvantage by reducing the allowable emission by 33 percent. Further, the commenter noted that new round top furnaces are not allowed the 33-percent emission limit reduction in the proposed rule, so operators installing new round top furnaces would be forced to petition on a case-by-case basis to demonstrate impracticability. The commenter recommended that if the EPA finalizes this provision, round top furnaces should be categorically exempt from any hooding requirements because it is impractical to install hoods and because the EPA should not burden state and local agencies with the need to make case-by-case determinations when they can be categorically exempt.

In a comment on the supplemental proposal, one commenter stated that the EPA offers no explanation for limiting the exemption to install ACGIH-compliant hoods for testing to existing round top furnaces only. The commenter stated that they own and operate several existing and new source round top furnaces for which the physical configuration and operation is very similar. The commenter stated that they will construct new or reconstruct existing round top furnaces in the future and that it would be impracticable to construct hoods of any type on any of these furnaces regardless of whether they are existing, new, or reconstructed sources. The commenter recommended that the EPA include new and reconstructed furnaces in its hooding exemption.

In a comment on the supplemental proposal, one commenter stated that, for a variety of design, technical, operational, and safety reasons, it is impractical to install temporary hooding on round top furnaces for performance testing and agreed with our proposed exemption from the performance test hooding requirements for existing round top furnaces. The commenter disagreed, however, with our not proposing an exemption for ''new or reconstructed'' sources (including round top furnaces), asserting that the same fundamental design factors that prohibit installation of temporary hooding on existing round top furnaces also prevent its installation on new round top furnaces. The commenter requested that the word ''existing'' be removed from the round top furnace exemption language proposed in 40 CFR 63.1512(e)(4)(iii) and that the words ''or reconstructed non-round top'' be added to (5) such that it reads

''(5) When testing a new or reconstructed, non-round top uncontrolled furnace the owner or operator must . . .''

One commenter maintained that allowing facilities to petition permitting authorities that such hoods are impractical is not an acceptable alternative to the proposed rule and suggested that the EPA allow site-specific procedures in OM&M plans for group 1 uncontrolled furnaces to minimize fugitive emissions.

One commenter asserted that the proposed ACGIH hooding requirement ignores the consideration that the EPA made for fugitive emissions in the original MACT floor determination and implements requirements for ACGIH hooding that go beyond the floor. The commenter stated that, in the 2000 Secondary [Aluminum] MACT rule, performance testing of controlled sources was conducted to define the MACT floor. Although some fugitive emissions were visible near capture hoods, the EPA did not specify a numerical capture efficiency requirement, visible emissions limit, or specific limits or criteria for capture systems. Instead, the EPA included a provision to address hooding systems to capture and collect emissions by including guidelines published in Chapters 3 and 5 of ACGIH *Industrial Ventilation: A Manual of Recommended Practice*, which is incorporated into the rule by reference. The commenter stated that owners/operators of sources with existing add-on control systems have been challenged with regard to the capture/collection system design guidelines in the ACGIH manual, and, according to the commenter, there have been instances when there has been a misuse of the ACGIH Industrial Ventilation Manual. The commenter asserted that the EPA and some permitting agencies are interpreting the manual and incorporating portions of various charts, tables and text as regulatory requirements. The commenter stated that the authors of the ACGIH Industrial Ventilation Manual did not intend, and specifically state in the Forward of the manual that ''The manual is not intended, to be used as law, but rather as a guide.''

One commenter contended that in the original MACT proposal and rulemaking, the EPA provided no supporting data to demonstrate that the MACT floor technology control systems tested for each Secondary Aluminum Production source category is actually capable of meeting the capture/collection system design requirements in the ACGIH manual. The commenter asserted that the EPA and some permit authorities during implementation of the rule, without supporting documentation, imposed specific capture/collection system design requirements on all existing add-on control systems that effectively exceed the MACT floor determinations. The commenter further asserted that the EPA did not follow the regulatory procedures for going ''above the floor'' during the rulemaking process in imposing more stringent hooding requirements.

In a comment on the supplemental proposal, one commenter stated that, if the EPA retains the requirement that uncontrolled furnaces conduct performance testing using ACGIH-compliant hooding, the current emission limits for group 1 uncontrolled furnaces should be reevaluated. The commenter stated that the supplemental proposal sets new requirements for uncontrolled furnaces that go beyond the existing MACT floor and was based upon a 33-percent reduction developed from limited data. The commenter requested that the EPA collect more emissions data from uncontrolled furnaces tested with ACGIH capture hoods and make new MACT floor determinations and set new numerical emission limits that properly account for the higher total emissions caused by the collection of fugitive emissions collected by the ACGIH-compliant hoods.

Several commenters maintained that the EPA is basing the proposed ACGIH hooding requirement on a limited, unrepresentative, and flawed dataset.

One commenter expressed concern that the dataset on which the EPA based their proposed action was made available only after publication of the proposal. The commenter stated that due to the limited information available to the industry, no additional testing has been performed to assess the impact of the proposed action, or its economic or engineering feasibility.

Two commenters observed that the EPA has erroneously based the 67-percent hooding assumption on very limited test data from two furnaces operating with forced-draft fans, a scenario that is atypical of uncontrolled furnaces, which are normally operated under natural draft. The commenter believes that the ''hooding efficiency'' measured during these tests is not representative because of the extremely high design flow rate of the capture hoods. The commenters maintained that exhaust flow at the hood was three times the stack exhaust flow rate, causing furnace emissions to be drawn out of the furnace door rather than allowing these emissions to exhaust through the stack.

One commenter cited an RTI memorandum to Rochelle Boyd, Environmental Engineer at the EPA, regarding the testing period reported for September 5, 2007, as a basis for the claim that errors were made during data collection, and that the EPA may be basing their decision and approach to regulating fugitive emissions on one dataset. The commenter emphasized that there are many furnace configurations that are used in the industry, so the EPA's one limited dataset cannot be representative of the entire industry. The commenter provided a copy of a table provided to the EPA by the commenter on December 21, 2011, outlining the inherent difference between several major furnace types.

One commenter stated that this proposal, in regard to installing hooding that meets ACGIH guidelines, is inconsistent with the requirement for existing sources that the MACT floor must equal the average emissions limitations currently achieved by the best-performing 12 percent of sources in that source category if there are 30 or more existing sources or, if there are fewer than 30 existing sources, then the MACT floor must equal the average emissions limitation achieved by the best-performing five sources in the category.

In a comment on the supplemental proposal, one commenter stated that they are concerned that the hooding and capture efficiency provisions in the 2014 supplemental proposal are unnecessary and actually reflect ''beyond the floor'' provisions for the installation of specific capture/collection systems that are not justified by the MACT floor determination calculations and evaluations.

One commenter stated that given the lack of evidence supporting these provisions, the commenter believes 40 CFR 63.1512 should be eliminated from the final rule.

Several commenters stated that ACGIH-compliant hoods are impossible to install on many group 1 uncontrolled furnaces due to the engineering limitations and considerations of many furnace installations such as size, type and location of the furnace. One commenter provided three examples of existing furnace installations that are unable to meet the requirements for fugitive emissions testing.

One commenter discussed round top furnace operations and how normal operations would not allow hooding for fugitive emissions.

One commenter stated that installation of temporary hooding on round top charge melters of the type the commenter has at its plant located in Lewisport, Kentucky, is not possible, and due to installed furnace design it is not possible to install temporary hoods on some reverberatory furnaces. The commenter included as attachments background information about the Lewisport testing.

One commenter stated that for group 1 uncontrolled furnaces, the proposed 33-percent emission reduction is a mandatory reduction for some operations, and also eliminates future operating flexibility for operations that are currently operating near the proposed 67-percent emission level. According to the commenter, the margin between operating levels and actual limits represents a margin of safety for furnaces that experience normal variations to be in continuous compliance.

The commenter maintained that the EPA proposed the 33-percent reduction in emissions without proof or justification that there are in fact fugitive emissions being released at or near these levels or for durations seen in the limited data the EPA provides. The commenter recommended that the EPA promulgate a rule that maintains a level playing field for the companies affected by the rule.

Two commenters recommended that the EPA allow the option to apply the assumed 67-percent capture efficiency for new furnaces to avoid the added cost of installing temporary hooding where a furnace can be operated in a manner that meets the 67-percent emission limit by changing the proposed requirement in 40 CFR 63.1512. The commenters argued that the proposed approach essentially forces the installation of a costly hood for new furnaces even when such hoods are not needed due to good pollution prevention practice and the resulting low HAP emission rates. The commenters opposed the HAP emission rate adjustment for new uncontrolled furnaces in instances where ACGIH hooding specifications are not possible, as the EPA proposed in 40 CFR 63.1512(e)(4)(ii), and asked that it be removed.

In a comment on the supplemental proposal, one commenter stated that in the original 40 CFR 63.1500, Applicability, and 40 CFR 63.1501, Dates, there are references to equipment that is ''new'' and equipment that is ''existing'' depending on installation date. The commenter suggested that EPA revise 40 CFR 63.1512(e)(4) to read as follows:

''When testing an existing or new uncontrolled furnace, . . .''

One commenter stated that issues addressed in 40 CFR 63.1512(e)(4)(ii), in terms of assuming a 67-percent capture efficiency for the furnace exhaust, were previously covered in the stack testing protocols that are part of the commenter's Consent Decree (included as an attachment). The commenter requested that the EPA provide clarification that those protocols are not impacted by this rule making and remain fully acceptable.

Response: As discussed in the preambles and technical support documents to the 2012 proposal and 2014 supplementary proposal, the existing performance testing requirements in Subpart RRR that apply to group 1 furnaces without add-on APCD do not include specific requirements relating to capture and collection of emissions during performance tests conducted to ensure compliance with applicable emission standards. During performance testing of these sources, emissions may escape without being accounted for (*i.e.*, captured, collected, and measured) in the emissions test. Thus, the performance tests done to ensure compliance may not provide an accurate measure of whether the furnace is, in fact, meeting the applicable emission standards.

The ACGIH guidelines (as defined in 40 CFR 63.1503) provide specifications for the proper design and installation of capture and collection systems to minimize unmeasured emissions and ensure that process emissions are being properly captured and conveyed to an air pollution control device, where one is in place, and also ensures that emissions testing results are representative of total emissions. The Subpart RRR standard as promulgated in 2000 includes a requirement that all controlled emission units include capture and collection systems designed consistent with the ACGIH guidelines. As stated in our response to comments in the 2000 Subpart RRR rule, a capture and collection system meeting ACGIH criteria is necessary for occupational safety, and for assuring compliance with the emission standards. See *Summary of Public Comments and Responses on*

Secondary Aluminum NESHAP, December 14, 1999, in the docket for this rulemaking.

The emission standards that apply to all group 1 furnaces were based on data from systems that effectively capture and contain emissions at the source (minimizing unmeasured emissions) and convey the emissions to the control device for destruction or removal. In addition, a capture and collection system meeting ACGIH guidelines with good hooding design will result in a lower volume of exhaust air to be treated, and, in many cases, a smaller, lower-cost control device. The EPA considered an ACGIH-compliant capture and collection system to be part of MACT floor technology for affected sources with add-on controls (see 64 FR 6960, February 11, 1999).

The subpart RRR rule generally applied the same emission standards to uncontrolled group 1 furnaces as it did to controlled group 1 furnaces and thereby allowed secondary aluminum facilities to continue to have uncontrolled group 1 furnaces so long as they met similar emission standards as controlled group 1 furnaces. The lack of clarity on the level of unmeasured emissions that may be emitted from an uncontrolled group 1 furnace during performance testing has led to confusion in rule implementation, as well as significant concerns about the accuracy and appropriateness of the compliance determination protocol.

Because performance tests for uncontrolled group 1 furnaces may not accurately measure whether the furnace is in compliance with the applicable emission standards, the EPA concluded that a testing protocol for uncontrolled group 1 furnaces that allows a potentially significant portion of HAP emissions to be unmeasured and unaccounted for in determining compliance with emission standards is inadequate.

A testing procedure for uncontrolled furnaces that permits an unknown degree of variance in the amount of emissions that may escape measurement during performance testing could call into question whether the rule is adequately ensures that the furnaces are meeting applicable emission standards. The commenters' suggest that a compliance demonstration that does not account for unmeasured emissions is a necessary result of the development of the Subpart RRR emission standards. The commenters are, in effect, questioning whether the existing standards for uncontrolled group 1 furnaces are consistent with the MACT floor analysis, which was primarily based on the performance of controlled furnaces. Moreover, if the level of unmeasured emissions during performance testing cannot be quantified for purposes of determining compliance with Subpart RRR emission standards, there could be an issue regarding the extent to which such emissions are subject to any MACT standard.

We note that one commenter stated that if EPA finalizes the testing requirements for uncontrolled furnaces, the EPA should reevaluate group 1 uncontrolled furnace emission limits. The commenter suggested that EPA collect emissions test data from uncontrolled furnaces using ACGIH hooding, make new MACT floor determinations, and set new numerical MACT emission limits. The EPA believes requiring additional furnace testing and conducting further MACT rulemaking is not necessary to address unmeasured emissions during performance testing of uncontrolled furnaces. The EPA believes that the actions taken in this rulemaking are sufficient to address the issue.

Further, the EPA is not mandating ACGIH hooding during performance testing in all instances, but rather providing alternative compliance options for facilities to account for unmeasured emissions from uncontrolled group 1 furnaces during performance testing. Specifically, for existing uncontrolled furnaces we are requiring either the installation of temporary ACGIH hooding or an assumption of a specified capture efficiency for furnace exhaust. Requirements for new uncontrolled furnaces are discussed below. Although we proposed using a 67-percent capture efficiency in lieu of the installation of temporary ACGIH hooding, in light of comments, we have re-examined the testing data on which the proposed 67-percent capture efficiency assumption was based, and revised the assumed capture efficiency to 80 percent. This 80-percent capture efficiency is based on the highest average capture of the three HAP tested. See *Draft Technical Support Document for the Secondary Aluminum Production Source Category, Supplemental Proposal Technical Support Document for the Secondary Aluminum Production Source Category,* and *Technical Support Document for the Secondary Aluminum Production Source Category Final Rule,* all available in this rulemaking docket. We believe this revised percent capture efficiency assumption of 80 percent provides the best estimate of the capture efficiency of uncontrolled furnaces for the several pollutants being measured, based on the limited data available. Under these provisions, if the source fails to demonstrate compliance using the 80-percent capture efficiency assumption, the source must retest using hooding that meets ACGIH guidelines or petition the appropriate authority that such hoods are impractical and propose testing procedures that will minimize unmeasured emissions. The retesting or petition must occur within 180 days. The commenters have not demonstrated that these alternatives are inappropriate or inconsistent with the 2000 MACT floor.

Applying the same emission limits to uncontrolled group 1 furnaces as controlled group 1 furnaces necessarily depends on emissions from uncontrolled group 1 furnaces being adequately captured and collected or being reasonably accounted for when a performance test is conducted. The MACT floor analysis, and the emission standards established by that analysis, for all group 1 furnaces (including controlled and uncontrolled furnaces) incorporated well-designed and maintained capture and collection systems, such as those prescribed by ACGIH guidelines. The rule revisions being promulgated in this action address this need by allowing facilities to choose from the compliance options described above.

In addition, CAA section 63.7(d)(5) of the General Provisions, which applies to this rule, requires that the owner or operator provide the facilities necessary for safe and adequate testing of a source. Adequate testing includes the responsibility to either provide a means of directing emissions to the sampling train, or to measure the capture efficiency of the equipment used to direct the emissions to the sampling train so that the overall emissions from the source can be determined. The rule changes described above assist in implementing this requirement for uncontrolled group 1 furnaces.

In response to the commenter's concerns regarding the test results cited by the EPA, the EPA obtained additional information from personnel at the facility at which the tests were performed. This information, which is available in the docket, indicates:

- Although sampling was conducted for approximately 3 hours using the canopy hoods at the two furnaces, the charging doors were only open for approximately 15 minutes on one furnace, and approximately 30 minutes on the other furnace;
- The testing times at the furnace stacks for both furnaces were equal to the entire cycle time for the furnace (so there was no flaw in the testing periods, such that the furnace stack emissions

were not measured over the entire cycle);

• There was no introduction of dilution air between the furnace and the furnace stack sampling point; and

• The furnaces were operating in compliance with the NESHAP requirements.

Therefore, although the test data are limited, we have identified no flaws in the testing procedures that render the results invalid, and we believe it is reasonable to rely on the test data to support our rule revision. In addition, it is undisputed that the test data are from a Subpart RRR-affected facility, and the commenter did not provide specific reasons to support its assertion that the tested furnaces are not ''indicative'' of the source category nor did commenters submit testing data to contradict, alter, or draw into question the EPA's conclusions. The commenter also did not explain why, or at what level, different capture efficiencies should be used based on differences in pollutants. We are certain that at least some unmeasured emissions escape from all uncontrolled group 1 furnaces during testing. Therefore, the only question is what fraction of the total emissions is directed to the furnace stack for measurement, and what fraction escapes as emissions that are not measured. Our estimate, based on the limited dataset, is that 80 percent of emissions at uncontrolled furnaces are captured and directed to the stack for measurement, while 20 percent are emitted as unmeasured emissions. The revised testing procedures for uncontrolled furnaces were proposed in February 2012, with one comment period in 2012 and a second comment period after the 2014 supplemental proposal, giving commenters ample time to collect and submit to EPA additional emissions test data, although none were submitted. In the absence of additional data, we relied on the only data available, although, upon further analysis of the data, we revised the capture efficiency from 67 percent to 80 percent.

As noted by commenters, and supported by information they provided, the tops of round top furnaces must be removed for charging by cranes operating above the furnaces. Commenters stated that for a variety of design, technical, operational, and safety reasons, it was not feasible to install temporary hooding on existing round top furnaces. Based on our review of the information submitted by the commenters, we agree that ACGIH-compliant hoods are not possible to install on existing round top furnaces because the top of the furnace must be removed by a crane operating from above the furnace. We also agree that state and local agencies should not be burdened with the need for case-by-case impracticability determinations for existing round top furnaces. Consequently, we are excluding existing round top furnaces from the requirement either to install temporary ACGIH hooding or to use an 80-percent capture efficiency assumption as well as the requirement for a petition of impracticality, but instead round top furnaces must be operated to minimize unmeasured emissions during testing.

The commenters have not provided documentation to support an exclusion for other types of furnaces, such as box reverberatory furnaces and box reverberatory furnaces with a side door. For these furnaces, issues related to hooding during performance tests may or may not arise depending on the specific site installation, including factors such as the presence of surrounding equipment and other physical obstructions, limited access and overhead cranes that may make it impractical to install hooding. Therefore, the exclusion in the final rule applies only to existing round top furnaces.

We note that, as discussed above, the final rule also provides flexibility for furnaces other than round top furnaces. Where an ACGIH-compliant hood cannot be installed on a furnace for testing and an 80-percent capture efficiency is not used, the source can petition the appropriate authority that temporary ACGIH hooding is impractical for the source and propose alternative testing procedures that will minimize unmeasured emissions. In some instances, furnace emissions can be captured and measured without ACGIH hooding. For example, the building may be operated as an enclosure, and emissions from the building can be measured (*e.g.,* by installing a temporary fan and associated ductwork or a stack, and measuring emissions in that ductwork or stack). In addition, there is an alternate performance testing methods provision available in 63.1511(d).

We disagree that new furnaces should be allowed the option to assume 80 percent of emissions are directed to the stack for measurement. We are allowing existing uncontrolled group 1 furnaces to use the 80-percent capture efficiency assumption, since the physical limitations of an existing furnace are already established. However, this is not the case for a new furnace; for a new furnace, adequate testing of the source can be achieved through the design of the furnace. This need not involve installation of a hood, since, for example, the building, or portion of the building in which the new furnace is located, could be used as an enclosure for the purpose of testing. As we stated earlier, adequate testing includes the responsibility to either provide a means of directing emissions to the sampling train, or to measure the capture efficiency of the equipment used to direct the emissions to the sampling train so that the overall emissions from the source can be determined.

As discussed above, we have different requirements for new uncontrolled furnaces, including new uncontrolled round top furnaces, than for existing uncontrolled furnaces because we have concluded that proper conditions for testing are readily achieved in the design of a new furnace. However, in the specific case of reconstructed round top furnaces, we agree that they are likely to have the same physical constraints as existing round top furnaces that make it difficult or impossible to construct the temporary hooding needed for emissions testing. Therefore, the final rule provides reconstructed round top furnaces the same exemption from the provisions requiring the installation of temporary ACGIH hooding or the assumption of 80-percent capture efficiency as allowed for existing round top furnaces.

Regarding the commenter's reference to the conditions of their Consent Decree, the decree at paragraph 122 states clearly that each company is responsible for achieving and maintaining complete compliance with all applicable federal laws and regulations, and compliance with the Consent Decree does not necessarily mean compliance with the Clean Air Act or implementing regulations. Further, the Consent Decree does not limit the EPA's authority to revise Subpart RRR. Also note that the compliance date for the rule revisions concerning testing of uncontrolled furnaces is 2 years after promulgation. While it is not necessary to review the specific protocols of the Consent Decree for purposes of this rulemaking, the commenter can follow up with their EPA Regional Office regarding any concerns.

Comment: In a comment on the supplemental proposal, one commenter stated it should not be a prerequisite that facilities or emission sources must first conduct a failed compliance test using the 67-percent capture efficiency assumption prior to petitioning permitting authorities that ACGIH equivalent hooding is impractical under the provisions of paragraph (e)(6). According to the commenter, some facilities know upfront that installing a capture hood is impractical and that they cannot comply with a stack test assuming a 67-percent capture efficiency. The commenter recommended that the final rule provide owners and operators a third option to petition permitting authorities (prior to performance testing) that installation of hooding is impractical; this alternative would avoid costs associated with multiple performance tests, labor and administrative burdens and potential enforcement liability that would be associated a failed performance test.

A commenter on the supplemental proposal stated that many of the hooding provisions are unworkable in actual practice, and the commenter therefore supports the petition process proposed for alternate capture/collection systems, coupled with testing procedures designed to minimize fugitive emissions. The commenter stated that it is inefficient and a significant waste of resources to require initial testing under the assumption of a 67-percent capture efficiency for a facility where installing an ACGIH-compliant hood is impractical and the facility knows or expects that it cannot comply using the 67-percent capture efficiency assumption. The commenter suggests it would be more efficient to allow facilities the option to submit a petition regarding the impracticality of hooding coupled with proposed testing procedures that will minimize fugitive emissions during the testing before the next required performance test occurs rather than after; this will minimize the likelihood of retesting and result in significant monetary, labor and efficiency savings.

The commenter stated they assume that, in the event of testing/retesting following the approval of a petition demonstrating the impracticability of hooding requirements, the 67-percent capture efficiency provisions would not be applicable to the results of the testing/retesting. However, because it is not specifically stated, the commenter seeks a clear statement to that effect in the final rule.

The commenter requested that the language in 40 CFR 63.1512(e)(4) be revised as follows:

''When testing an existing uncontrolled furnace, the owner or operator must comply with the requirements of either paragraphs (e)(4)(i), (ii), (iii) or (iv) of this section at or prior to the next required performance test required by 63.1511(e).

(i) Install hooding that meets ACGIH Guidelines, or

(ii) At least 180 days prior to testing, petition the permitting authority for major sources, or the Administrator for area sources, that such hoods are impractical under the provisions of paragraph (e)(6) of this section and propose testing procedures that will minimize fugitive emissions during the performance test according to the paragraph (e)(7) of this section, or

(iii) Assume a 67-percent capture efficiency for the furnace exhaust (*i.e.,* multiply emissions measured at the furnace exhaust outlet by 1.5). If the source fails to demonstrate compliance using the 67-percent capture efficiency assumption, the owner or operator must re-test with a hood that meets the ACGIH Guidelines within 180 days, or petition the permitting authority for major sources, or the Administrator for area sources, within 180 days that such hoods are impractical under the provisions of paragraph (e)(6) of this section and propose testing procedures that will minimize fugitive emissions during the performance test according to paragraph (e)(7) of this section.

(iv) The 67-percent capture efficiency assumption is not applicable in the event of testing conducted under an approved petition submitted pursuant to (ii) or (iii) above.''

The commenter stated that making these changes will also require that the existing proposed paragraph (iii) be re-designated as (v).

Response: Based on the comments received, the EPA reevaluated the proposed requirements for testing uncontrolled furnaces. Based on our analysis of available data (described in the *Technical Support Document for the Secondary Aluminum Production Source Category Final Rule,* which is available in the docket), we believe that the vast majority of furnaces will be able to comply based on the 80 percent assumption. However, we agree that there might be cases where a facility owner or operator may know in advance that they cannot comply based on the 80-percent capture efficiency assumption and that installing ACGIH hoods for testing is not practical, so to require them to conduct tests that they know in advance will fail is unreasonable and unnecessary. Therefore, the final rule provides an alternative for such cases whereby the facility owner or operator can petition their permitting authority at least 180 days in advance that ACGIH hooding is impractical and request approval of alternative testing procedures including measures they will take that will minimize unmeasured emissions during testing. The EPA has also clarified in the final rule that in testing or retesting following approval of a petition demonstrating impracticability of temporary ACGIH hooding, the 80-percent capture efficiency assumption does not apply to the results of the testing or retesting.

Comment: In a comment on the supplemental proposal, one commenter requested that instead of the requirement for uncontrolled furnaces to conduct performance testing using ACGIH hooding, the EPA should allow, as they do for round top furnaces, the use of alternative procedures for the minimization of fugitive emissions during performance testing for consistency and cost considerations. The commenter stated that allowing all uncontrolled furnaces to use the work practices for the minimization of fugitive emissions, rather than install ACGIH hooding, would achieve the same capture efficiency during the performance test as it would for round top furnaces. The commenter further stated that the installation and use of an ACGIH hood is not cost effective and would create unnecessary costs simply to comply with testing requirements. A commenter on the supplemental proposal stated that the EPA should delete the ACGIH capture hood requirements for uncontrolled furnace testing and instead specify work practice alternatives for minimizing fugitive emissions during testing.

Response: The commenters have not provided documentation to support an exclusion from ACGIH hooding and associated requirements for furnaces other than round top furnaces. Based on the limited information available to the EPA, we believe that, for these furnaces, issues related to hooding during performance tests may or may not arise depending on the specific site installation, including factors such as the presence of surrounding equipment and other physical obstructions, limited access, and overhead cranes that may make it impractical to install temporary hooding. Therefore, the exclusion in the final rule applies only to existing or reconstructed round top furnaces. As noted above, even if ACGIH-compliant hoods cannot be installed on a furnace, in some instances, furnace emissions can be captured and measured without ACGIH hooding. For example, the building may be able to be operated as an enclosure, and emissions from the building can be measured (*e.g.*, by installing a temporary fan and associated ductwork or a stack, and measuring emissions in that ductwork or stack) if there are no other furnaces or other significant sources in the building of the pollutant to be measured. In addition, an owner or operator of an existing uncontrolled group 1 furnace other than a round top furnace has the choice of assuming an

80-percent capture efficiency for the furnace exhaust, or, if the source does not wish or fails to demonstrate compliance using the 80-percent capture efficiency assumption, the owner or operator may petition the permitting authority that such temporary hoods are impractical.

Comment: Three commenters cited safety concerns regarding the feasibility of fugitive emissions testing for group 1 uncontrolled furnaces.

One commenter asserted that because of the broad spectrum of furnace designs and safe operating practices for the group 1 uncontrolled furnace category, it is impossible to fully characterize the potential impacts on operator safety from EPA's proposed action. The commenter observed that to conduct an EPA Method 5 test at a hood requires an operator to be present for the duration of the emissions test in a location that industry standard safe operating practices prohibit. The commenter asserted that this proposed requirement would violate the industry standard operation procedure of the vast majority of group 1 uncontrolled furnaces, which require the removal of the operator from unsafe locations during normal furnace operation. The commenter stated that group 1 uncontrolled furnaces fall into two broad categories, those designed for operator presence on the furnace structure and those that do not have any infrastructure for operator presence above the furnace.

One commenter stated that safe operation of furnaces that charge aluminum scrap only allows for operators to access the area above the furnace when the door is closed, and the cycle is in a steady state (*i.e.,* not immediately following scrap charging), entirely precluding the operator from entering during operation. The commenter emphasizes that the operation of the proposed testing apparatus, in accordance with EPA Methods 1 and 2, would violate industry best practices for the safe operation of remelt furnaces.

Response: We disagree that the Method 5 emissions tests must be conducted ''at a hood,'' and therefore have potential impacts on the safety of the testing equipment operators or furnace operators. The ductwork from the hood can lead to the same stack as the furnace. Therefore, fugitive emissions captured by the hood can be combined with emissions from the furnace, and testing can be conducted at the same stack location as the facility has historically tested. Furthermore, existing uncontrolled furnaces have the additional option of assuming an 80-percent capture efficiency and all uncontrolled furnaces may petition the appropriate authority that such hoods are impractical and propose testing procedures that will minimize unmeasured emissions during testing.

Comment: Three commenters asserted that design and installation costs for hooding are far higher when testing for group 1 uncontrolled furnaces than those provided by the EPA. One commenter estimated a cost of $120,000 to $500,000 per hood.

One commenter noted that because these hoods and ductwork would have to be retrofitted to existing equipment, there is little or no economy of scale.

Response: The commenters did not provide supporting calculations or a breakdown for their cost estimates. The EPA contacted the commenter that provided the higher estimated costs and requested additional information on their cost estimate. The commenter provided cost estimates for an installation of hooding that meets ACGIH guidelines on a Reverb Melter ($208,146) and a Tilting Holder ($238,012). The EPA used these cost estimates in a supplementary cost analysis to provide further information concerning the rule amendments being adopted in this final rule *Cost Estimate for Rule Changes to Secondary Aluminum NESHAP,* which is available in the docket for this action. Based on the commenter's estimates, the average capital cost for the two installations is approximately $223,000. The 2012 cost can be scaled to 2011 cost by applying the ratio of the Chemical Engineering Plant Cost Index for March 2011 (final—575.9) to March 2012 (preliminary—596.1), or a ratio of 0.966. Using this factor, the capital cost is estimated to be $215,400 per furnace. If this value is used in lieu of the original estimate (contained in supporting documentation for the proposed rule) of $76,000 for a single hood, all costs would increase by a factor of 2.83 (*i.e.,* $215,400 divided by $76,000). Assuming temporary hooding will be installed on 107 furnaces, the total capital cost using this value would therefore conservatively be estimated to be $17,300,000 (*i.e.,* $6,099,000 multiplied by 2.83). Note that the $6,099,000 cost estimate is based on an average cost per furnace of $57,000, based on the assumption that a hood for a second installation at a facility would cost half as much (*i.e.,* ($76,000 + $38,000)/2 = $57,000). Similarly, using these higher cost estimates per furnace, the total annualized cost for the source category would be conservatively estimated at $3.46 million per year, and the total annualized cost per furnace would be approximately $32,300 per year. Therefore, conservatively assuming 107 furnaces install temporary hooding, total estimated annualized costs would range from $1.2 million per year to $3.46 million per year or an average of $2.3 million per year. Total annualized cost per furnace would range from $11,000 per year to $32,300 per year, or an average of $21,650 per year. We believe that these total cost estimates are conservative (more likely to be overestimates rather than underestimates) because these costs are based on the assumption that all of the estimated uncontrolled furnaces will choose to install temporary hooding rather than use the other options provided in the rule for addressing unmeasured emissions during performance testing.

Comment: Two commenters, in response to the 2012 proposed rule, requested that the EPA revise proposed 40 CFR 63.1512(e)(4)(ii) to list example work practices that the Agency considers acceptable for minimizing furnace fugitive emissions during a performance test. The commenters stated that the list of examples would provide permitting authorities some basis for evaluating proposed work practices and approving test procedures.

In a comment on the supplemental proposal, one commenter stated that, with the approval of the applicable permitting authority, when testing an uncontrolled reverberatory furnace, they have used a test plan that includes positioning one or more fans to direct flow into a furnace when the door is opened in order to minimize fugitive emissions escaping the furnace door. The commenter recommended paragraph 63.1512(e)(7)(x) be added to read as follows:

''(x) Use of fans or other device to direct flow into a furnace when door is open.''

In a comment on the supplemental proposal, one commenter stated that most of the ''testing procedures'' presented in sections 63.1512(e)(7)(i) through (ix) of the proposed rule are reasonable suggestions for minimizing fugitive emissions. However, the commenter stated that, the installation of temporary baffles would have no practical effect on reducing fugitive emissions for the types of emission units regulated under this source category. The commenter stated that, additionally, increasing the exhaust rate will require additional fuels to be combusted and will cause an increase in dross production; both will result in particulate and HCl emission increases that would otherwise not be created. According to the commenter, the creation of additional dross will produce a cascade of collateral environmental impacts: More dross must be processed, more dross processing HAP will be created, and there will be more residuals to be handled, transported and disposed.

In a comment on the supplemental proposal, one commenter stated that the language the EPA uses to introduce the procedures that can be used to minimize fugitive emissions in the preamble is better than that used in the original proposed rule at 63.1512(e)(7). The commenter stated that the preamble introduces alternatives for minimizing fugitive emissions with the words, ''[t]hese procedures may include, if practical, one or more of the following, but are not limited to . . . .'' The commenter stated that, in contrast, the proposed rule at 40 CFR 63.1512(e)(7) simply states, ''testing procedures that will minimize fugitive emissions may include, but are not limited to . . . .'' The commenter recommended that the EPA should include the phrase ''if practical, one or more of the following'' in the language of the rule at 40 CFR 63.1512(e)(7), because this construction makes clear that not every alternative to minimize fugitive emissions may be practical and therefore not all the listed alternatives are required.

In a comment on the supplemental proposal, one commenter stated that they have conducted testing of round top melting furnaces after development of a test plan, with the EPA's approval, as part of a Consent Decree and as approved by the applicable permitting authority. The commenter stated that this procedure involves removing the top once and placing a representative but lighter charge into the furnace and replacing the top. The commenter stated that the charge includes all materials normally charged into the furnace but a charge size of approximately 25 percent to 35 percent of normal; this procedure minimizes fugitive emissions from the furnace. The commenter stated that while they believe this procedure meets the intent of paragraph 63.1512(e)(7)(v), they request that the paragraph be revised as follows:

(v) ''In order to minimize time the furnace door or top is open, it is permissible to add a smaller but representative charge into the furnace at one time and conduct the test without additional charge.''

Response: In response to the commenters' requests, we have included in the final rule a list of example procedures for minimizing unmeasured emissions during testing. These procedures may include, if practical, but are not limited to, one or more of the following:

- Installing a hood that does not meet ACGIH guidelines;
- Using the building as an enclosure, and measuring emissions exhausted from the building if there are no other furnaces or other significant sources in the building of the pollutants to be measured;
- Installing temporary baffles on the sides or top of the furnace opening, if it is practical to do so where they will not interfere with material handling or with the furnace door opening and closing;
- Minimizing the time the furnace doors are open or the top is off;
- Delaying gaseous reactive fluxing until charging doors are closed and the top is on;
- Agitating or stirring molten metal as soon as practicable after salt flux addition and closing doors as soon as possible after solid fluxing operations, including mixing and dross removal;
- Keeping building doors and other openings closed to the greatest extent possible to minimize drafts that would divert emissions from being drawn into the furnace;
- Maintain burners on low-fire or pilot operation while the doors are open or the top is off;
- Use of fans or other device to direct flow into a furnace when door is open; or
- Removing the furnace cover once in order to add a smaller but representative charge and then replacing the cover.

We disagree that baffles would be ineffective in reducing unmeasured emissions in all cases and note that they are just one of several options that can be used, as appropriate, to reduce unmeasured emissions during testing of uncontrolled furnaces. One way that baffles can reduce unmeasured emissions is to keep the smoke puff that escapes the furnace when the scrap is first put in from leaving the area around the furnace. Therefore, some of the smoke can be pulled back into the furnace after the seconds-long initial puff of smoke. Baffles also tend to produce a higher-velocity corridor leading to the furnace face, also making it more likely that the puff of smoke that escapes the furnace during charging will subsequently get pulled back into the furnace. Furthermore, their use would be temporary only for the time that the furnace doors are open to accept a charge. As proposed, the final rule includes the use of baffles as one testing procedure that can be used to minimize unmeasured emissions but does not require that they be used.

We agree with the comment that increasing exhaust rate may tend to increase dross production, with a resultant increase in PM and HCl emissions. Therefore, even though increasing exhaust rate will improve capture, we are removing the example of raising flow rate from the list of methods to minimize fugitive emissions.

We disagree with the comment that 40 CFR 63.1512(e)(7) does not adequately introduce the procedures that can be used to minimize unmeasured emissions. We believe that the wording at 40 CFR 63.1512(e)(7) clearly conveys that any one of the listed procedures, or others that are not listed, may be used to minimize unmeasured emissions during testing. The regulatory wording does not require their use. Therefore, the final rule has not been revised as requested by the commenter.

We agree that, as the commenter recommended, using a smaller but representative charge, could reduce the amount of time that furnace doors are open, and could therefore reduce the amount of emissions that are not captured and measured during testing of uncontrolled furnaces. Because emission limits for group 1 furnaces are in units of mass of pollutant per unit of mass of feed, the mass of the charge by itself does not affect the validity of test results. The final rule includes the use of smaller but representative charges as another alternative to minimizing unmeasured emissions during testing of uncontrolled group 1 furnaces. If a single test condition is not expected to produce the highest level of emissions for all HAP, testing under two or more sets of conditions (for example high contamination at low feed/charge rate and low contamination at high feed/charge rate) may be required.

Comment: Two commenters on the 2012 proposal requested that the EPA extend the timeline proposed for retesting under 40 CFR 63.1512(e)(4)(ii) to 240 days. The commenter asserted that the requirement proposed in 40 CFR 63.1512(e)(4)(ii) to ''retest with a hood that meets ACGIH Guidelines within 90 days'' is not practicable. For the proposed provision to be workable, the commenter argued, the EPA needs to allow at least 240 days for retesting with an ACGIH hood if a source fails to demonstrate compliance using the 67-percent capture efficiency assumption.

Response: The EPA agrees with commenters that the 90-day period for retesting in the 2012 proposal was insufficient. Based on further review and comments received, in the supplemental proposal, the EPA proposed a 180-day period for the retesting provisions in section 63.1512(e)(4). We received no comments on the 2014 supplemental proposal objecting to the 180-day retesting period. Therefore, instead of the initially proposed 90-day retesting period, we are adopting in the final rule a 180-day period for a source that fails to demonstrate compliance using the capture efficiency assumption either to: (1) Retest with an ACGIH-compliant hood; or (2) petition the permitting authority that such hoods are impractical for the furnace and propose testing procedures that will minimize unmeasured emissions during testing.

Comment: In a comment on the supplemental proposal regarding 40 CFR 63.1512(e)(4)(iii), one commenter stated that it is not clear if the EPA intends to exempt all round top furnaces in operation on the publication date of the proposal, or if round top furnaces that commenced construction or reconstruction after February 11, 1999, (new) are purposely being excluded. The commenter suggested the language be revised to the following:

''Existing and new round top furnaces are exempt . . . .''

Response: As proposed in the 2014 supplemental proposal, the final rule exempts existing round top furnaces from the testing requirements for uncontrolled furnaces in 40 CFR 63.1512(e)(4)(i), (ii), and (iii). In response to a comment on the supplemental proposal, we have expanded the exemption to also apply to reconstructed round top furnaces. The intent of the EPA is that existing and reconstructed round top furnaces that commenced construction or reconstruction on or before February 12, 2012, are exempt, and new round top furnaces that commence construction after February 12, 2012, are not exempt, from the testing requirements for uncontrolled furnaces in 40 CFR 63.1512(e)(4)(i), (ii), and (iii). Therefore, we are not adopting the revised language suggested by the commenter.

Comment: One commenter asked that the EPA clarify in 40 CFR 63.1512(e)(4)(ii) what constitutes ''impractical'' with respect to installing temporary capture hoods.

Response: In response to the commenter, 40 CFR 63.1512(e)(6) of the final rule clarifies in what circumstances installation of temporary capture hoods would be considered impractical.

Temporary capture hooding installation is considered impractical if:

- Building or equipment obstructions (for example, wall, ceiling, roof, structural beams, utilities, overhead crane, or other) are present such that the temporary hood cannot be located consistent with acceptable hood design and installation practices;
- Space limitations or work area constraints exist such that the temporary hood cannot be supported or located to prevent interference with normal furnace operations or avoid unsafe working conditions for the furnace operator; and/or
- Other obstructions and limitations subject to agreement of the permitting authority.

4. What is the rationale for our final approach for testing of uncontrolled group 1 furnaces?

As discussed above and in the 2012 and 2014 proposals, we are finalizing compliance alternatives addressing capture and collection of emissions for uncontrolled furnaces during performance testing. Owners and operators of uncontrolled furnaces have the options of installing temporary ACGIH-compliant hooding for testing or assuming that the capture efficiency of the furnace exhaust is 80 percent without installing hooding. Further options are provided if a source fails to comply using the 80-percent capture efficiency assumption or decides not to use the 80-percent assumption and instead petitions at least 180 days in advance that ACGIH hooding is impractical for the furnace and for approval of alternative testing procedures, including measures that will minimize unmeasured emissions during testing. The final rule exempts existing and reconstructed round top furnaces from these requirements due to the infeasibility of installing hooding. The final rule clarifies the circumstances under which the installation of temporary ACGIH hooding is considered impractical and specifies work practices that can be used to minimize unmeasured emissions during testing of uncontrolled furnaces.

D. Changing Furnace Classification

1. What did we propose regarding changing furnace classification?

In the 2012 proposal, we proposed to address an area of uncertainty under Subpart RRR by specifying in 40 CFR 63.1514 rule provisions expressly allowing changes in furnace classification, subject to procedural and testing requirements, operating requirements and recordkeeping requirements. We proposed a frequency limit of no more than one change in classification (and associated reversion) every six months, with an exception for planned control device maintenance activities requiring shutdown. We received comments on the 2012 proposal requesting additional or unlimited changes in furnace classification. Based on the information received, we reevaluated the appropriate limit on frequency of furnace classification changes. The EPA received from one commenter an inventory of the number of classification changes that occurred each year at a specific Subpart RRR furnace over a nearly 10-year period (available in the docket for this rulemaking). The highest number of furnace classification changes in one year, including both planned and unplanned changes, was nine.

Based on the comments and information received, we proposed in our 2014 supplemental proposal a revised limit on the frequency of changes in furnace classification of four in any 6-month period, with a provision allowing additional changes by petitioning the appropriate authority.

2. What changed since proposal regarding changing furnace classification?

Based on our consideration of the comments and additional information received following the 2012 proposal and the supplemental proposal, the following changes are incorporated into the final rule:

- Added a provision that if compliance has already been demonstrated for a given operating mode, performance testing is not required, provided the testing was in compliance with the provisions in 40 CFR 63.1511;
- Added clarification in §§ 63.1514(a)(2)(iii) and (4)(iii), (b)(2)(iii) (b)(4)(iii), and (c) on establishing the number of tap-to-tap cycles elapsed (or time elapsed for continuously operated units) during performance testing as a parameter to be met before changing to uncontrolled mode, and provisions for continuous operations;
- Removed the proposed requirement to complete one or more charge-to-tap cycles or 24 hours of operation prior to changing furnace operating mode in §§ 63.1514(2)(i) and (4)(i), (b)(2)(i), (b)(4)(i), (c)(2)(i), (c)(4)(i);
- Added 40 CFR 63.1514(b)(4)(iv) that requires that D/F emissions determined at performance test must not exceed 1.5 ug D/F TEQ/Mg of feed/charge to demonstrate that it qualifies as a group 2 furnace. This section was added for consistency with § 63.1514(b)(2)(iv);
- Clarified §§ 63.1514(c)(5) and (6) with respect to requirements for changing operating modes between a group 1 and a group 2 furnace; and
- Removed the proposed requirement for area sources to conduct performance

tests every 5 years in 40 CFR 63.1514(d)(2).

3. What key comments did we receive regarding changing furnace classification?

Comment: Several comments were received objecting to the proposed limits on the frequency of changing furnace classification. Four commenters on the 2012 proposal asked that the EPA allow controlled furnaces to change operating modes more frequently than once every 6 months. The commenters particularly noted the need for flexibility for unplanned baghouse maintenance and repair. Although the 2012 proposed rule allows a change of operating mode for planned maintenance of air pollution control devices, the commenters stated that a restriction to ''once every 6 months'' for unplanned maintenance is ill-advised because such a restriction may result in shutdown of the entire casting operation or encourage an owner or operator to delay baghouse shutdown and repairs that could be initiated immediately by changing to a ''cleaner'' operating mode that has already been demonstrated to comply with the applicable emission limits. One commenter stated that the proposed limit (of once every 6 months) on the frequency of changes other than for ''planned'' maintenance would severely limit facility flexibility. One of the commenters requested the EPA to revise 40 CFR 63.1514(e) to allow controlled furnaces to change operating modes (and revert to prechange operating mode) without restriction on frequency, when the air pollution control device must be shutdown for both planned and unplanned maintenance.

One commenter on the 2012 proposal noted that in the proposed 40 CFR 63.1514(e), the proposed requirements for operating in different modes include testing to demonstrate compliance under each mode, revising the OM&M plan to reflect all planned operating modes and revising labels to display compliant operating parameters for each operating mode. The commenter observed that the EPA has listed recordkeeping requirements when changing furnace classifications, but the EPA has not listed any barriers to implementation or enforcement once a stack test has been performed demonstrating compliance and an OM&M plan submitted. The commenter concludes that if tests prove compliance while operating in each mode, there is no justification for restricting the frequency of changes.

One commenter noted interactions over several years between the commenter and the EPA regarding the use of alternative operating scenarios. The commenter stated that those communications (and litigation) resulted in a February 16, 2012, Applicability Determination (which was attached to their comment). The commenter noted that the commenter had explained the need for flexibility to change operating modes in this proposed rule to EPA in a letter dated January 18, 2012, (also attached to their comment). The commenter recommended that the EPA use the approach in the February 16, 2012, Applicability Determination in Subpart RRR.

In a comment on the 2014 supplemental proposal, one commenter stated that the EPA has not adequately explained why it is proposing to allow 4 changes in furnace operating mode, or provided any reasoned explanation for why these changes are lawful and reasonable, in view of the requirement that standards apply at all times. The commenter stated that before allowing such changes to be made by a facility, the EPA must ensure that this is not equivalent to an exemption from the standards, which a facility may take advantage of under the EPA's proposal four times a year.

Response: As discussed in the preamble to the 2012 proposed rule, the EPA proposed to address an area of uncertainty under Subpart RRR by allowing changes in furnace classification, or furnace operating mode, subject to procedural and testing requirements and a limit on frequency of no more than one change (and associated reversion) every 6 months. As summarized above, the EPA received comments on the 2012 proposal requesting additional or unlimited furnace classification changes. Based on the comments received, the EPA reevaluated the limit on frequency of furnace classification changes. The EPA received from a commenter an inventory of the number of classification changes that occurred each year at a specific furnace over a nearly 10-year period (available in the docket for this rulemaking). The highest number of furnace classification changes for this furnace in one year, including both planned and unplanned changes, was nine.

In response to the comments and information received and because of the potential difficulty in distinguishing between a planned and unplanned change, in the 2014 supplemental proposal we proposed a revised frequency limit of four (including the four associated reversions) in any 6-month period, including both planned and unplanned events, with a provision allowing additional changes by petitioning the appropriate authority. The EPA explained that the revised limit balances the interest in allowing furnace classification changes while preserving the EPA's and delegated authorities' practical and effective enforcement of the emission limitations, work practice standards, and other requirements of Subpart RRR.

Based on the EPA's experience in overseeing facilities' compliance with the Subpart RRR NESHAP, the EPA believes it will be challenging in many circumstances for a regulatory compliance inspector to retroactively confirm which of two scrap inventories (*i.e.*, one clean charge and the other non-clean charge) was processed in a furnace at a given time in the past, and whether the allowed type of feed/charge was used for the furnace classification that was applicable for that time period. Similarly, it may be difficult to determine if the flux type and flux rate applied during that time period were compliant with the then-applicable furnace classification. The difficulty of verifying the inputs to the calculations used to determine SAPU emission limits, and daily and rolling average SAPU emission rates when furnace control device status and feed/charge type are frequently changed for one or more emission units within a SAPU may lead to further uncertainty in verifying compliance. On-site inspections may be difficult to conduct properly if the selected provisions of the OM&M plan applicable to furnace operation on the day and time of the inspection are subject to frequent change. For all of these reasons, increased frequency of allowed furnace classification changes places greater burdens on regulatory oversight agencies and personnel and creates the potential for impaired regulatory oversight.

In recognition of the issues raised by allowing repeated changes in furnace classification and applicable emission standards, the EPA is finalizing a limit of four on the number of times in a 6-month period a Subpart RRR facility may change classification of a furnace (*e.g.*, changing furnace classification from a controlled group 1 furnace to an uncontrolled group 2 furnace, and back). The EPA appreciates the value in providing operational flexibility for regulated sources, but believes the limit is necessary to ensure effective implementation and regulatory oversight of the rule. Facilities are allowed to change furnace classification up to four times during a 6-month period. The final rule clarifies that a change from one operating mode to another and back is considered one change in operating mode. The EPA believes allowing unlimited changes of furnace classification would be impractical, as the monitoring, recordkeeping, reporting, and labeling requirement changes associated with changing furnace classifications would be difficult for the regulated community to follow and for the regulatory agencies to determine and verify continuous compliance. Furthermore, the EPA and state agency experience has shown that some facilities have difficulty preventing excess emissions from entering the flue gas from group 1 furnaces, and, therefore, changing from a group 1 furnace to a group 2 or uncontrolled group 1 status using cleaner charge may not necessarily result in a reduction of emissions. More frequent changes in furnace classifications could result in a greater potential for excess emissions in some instances. The EPA selected the number of allowable changes in furnace classifications based on information and data received from industry on the number of changes in furnace classification over an annual period. The EPA believes that four changes per 6-month period will allow industry the flexibility it needs while maintaining confidence in the level of implementation, compliance and enforcement that can be achieved in changing from one classification to another. If a source needs additional classification changes in a 6-month period, the rule allows the source to petition the appropriate authority for approval.

Following the 2014 supplemental proposal, we received two positive comments from industry on the revised frequency limit and the option to request additional changes if needed. Only one comment was received opposing the revised frequency limit. It does not appear to the EPA that the ability to change furnace modes has been an issue for most of the secondary aluminum production industry. Furthermore, the commenter opposing the revised limit did not provide additional data to support a greater frequency or the need for an unlimited frequency. We note that in the supplemental proposal, we specifically requested ''any commenter who would like the EPA to consider a different limit on frequency to include a specific rationale and factual basis for why a different frequency would be appropriate as well as any data on historical frequencies of furnace classification changes under subpart RRR.'' 79 FR at 72902. In addition, the EPA is finalizing a rule provision to allow the industry to request approval for a greater frequency of furnace classification changes if needed for their particular operation. Based on data from industry and the comments received on the supplemental proposal, we do not believe that it is necessary to further revise the limit on the frequency of furnace changes. In this final rule, we allow four changes in furnace classification per 6-month period with the option of requesting in advance additional changes from the appropriate authority.

In response to the same commenter's suggestion that EPA ''adopt the approach'' in a 2012 EPA letter allowing changes in classification for a furnace owned by the commenter, the EPA notes the letter addressed only a single, relatively unusual ''tilt type'' reverberatory furnace ''in contrast to most reverberatory furnaces'' and was located at an area source subject only to D/F limits and not the other limits applicable to major sources under Subpart RRR. The letter also expressly provided that it did not limit the EPA's authority to revise Subpart RRR requirements through rulemaking.

We believe the February 16, 2012, applicability determination is conceptually consistent with the rule changes, particularly for the specific type of furnace at issue in that determination. The Subpart RRR rule changes build upon several elements of the February 16, 2012, determination to address concerns that switching operating modes for any furnace subject to Subpart RRR be done in a manner that is fully compliant with Subpart RRR for each operating mode, while at the same time avoiding overly burdensome requirements for industry.

In response to the commenter on the 2014 supplemental proposal who asserted that EPA has not adequately explained how it is lawful and reasonable to allow four furnace classification changes per year in view of the requirement that standards apply at all times and must ensure this is not an exemption from standards, we provided such an explanation in the 2012 proposed rule preamble, and the commenter did not submit any comments in response to the 2012 proposed rule. In the 2014 supplemental proposal, we proposed a revised limit on frequency of classification changes, but we proposed no other revision and stated we ''are not requesting comments on any other aspect of the proposed provisions for furnace classification changes.'' 79 FR at 72902. The comment refers to the revised proposed limit of four changes (per 6-month period, not per year as described by the commenter), but the substance of the comment concerns continuity of emission standards and potential exemption from standards, which are not specific to the frequency limit and were addressed previously in the 2012 proposal.

We note that the rule ensures this is not an exemption from standards. As discussed above, there was uncertainty about whether Subpart RRR allowed changes in furnace classification, but, at least in some specific circumstances and conditions, furnace classification changes were allowed under the existing rule. The EPA addressed the issue in the 2012 and 2014 proposals and is finalizing rule provisions clarifying the procedural, testing, operating, and recordkeeping requirements when changing furnace operating modes, so as to ensure continuous compliance with Subpart RRR standards. The final rule specifies how a furnace can lawfully change from one operating mode under the rule to another and does not at any time exempt a furnace from meeting applicable standards.

Comment: Several commenters objected to the EPA's addition to Subpart RRR of any provisions regulating the changing of furnace classification. A commenter on the 2012 proposal stated that the proposed rule will severely restrict flexibility, while the EPA is taking credit for saving the industry $600,000 by ''allowing'' actions that were previously unrestricted. The commenter proposes that all language pertaining to furnace change classification be removed from the proposed rule.

In a comment on the 2014 supplemental proposal, one commenter stated that any restrictions on changing furnace classification are unnecessarily burdensome and do not provide any additional environmental benefit. The commenter stated that Subpart RRR as promulgated in 2000 provides sufficient basis for facilities to change furnace classification while maintaining compliance with the emission limits and other requirements. The commenter attached a 2012 letter from Edward J. Messina, in which the EPA acknowledges that a facility ''may change operating modes consistent with Subpart RRR'' and ''can comply with Subpart RRR when it operates within one (and only one) of three proposed operating modes for the entirety of any given melt cycle.'' The commenter provided a copy of the 2012 letter as part of their submittal. The commenter stated that they revised their

Kalamazoo, Michigan, facility's Permit to Install, to include the ability to change furnace classification consistent with the EPA's 2012 letter and have successfully changed from group 1 to group 2 operation in response to unexpected baghouse system malfunctions while maintaining compliance with the applicable emission limits and other requirements of Subpart RRR.

In a comment on the supplemental proposal, the same commenter stated that the EPA attempts to justify the restrictions on changing furnace classification as necessary for practical and effective enforcement of Subpart RRR; however, the EPA does not mention any occasion in the 14 year history of the MACT rule when a facility's use of these provisions has resulted in any problem related to enforcement or compliance. The commenter stated that facilities have been using the ability to change furnace classification while maintaining compliance with all of the requirements of Subpart RRR for some time without creating any enforcement or compliance problems. The EPA has provided no rational basis for imposing this additional regulatory burden. The commenter recommended the EPA adopt the approach to changing furnace classification provided in the 2012 EPA determination (the commenter attached the 2012 letter to their comments), which does not restrict frequency of changes and does not require testing with a number of cycles of clean charge prior to unplanned changes, which is unnecessary and impracticable.

Response: The EPA disagrees that changes in furnace classification were unrestricted prior to this rulemaking. As explained in the preamble to the proposed rule, the existing Subpart RRR regulatory text did not explicitly address whether and under what conditions a furnace may change its classification from one operating mode to another. This led to uncertainty for facilities and permitting authorities when considering and evaluating compliance options. The rule provisions governing changes in furnace classification are intended to provide clarity and add flexibility for the industry when, for example, normal feed materials are temporarily unavailable and there is a desire by the facility to operate the furnace in a different mode.

We disagree with the commenter's assertion that there have been no problems related to enforcement or compliance for facilities changing furnace classification in the 14-year history of the MACT rule. Although we have very limited data on the practice of changing furnace classification in the industry, in part because we received data from only two companies following the 2012 proposal, we know that some facilities have submitted requests to authorities that they be allowed to change furnace classification and some of these requests were denied. In such cases, the absence of national regulations clearly stating whether and under what conditions the practice is allowed under Subpart RRR served to limit compliance flexibility and was potentially costly to facilities that sought to change their furnace operating mode. Therefore, the addition of these provisions provide clear instructions to regulatory agencies and the industry on the criteria and procedures necessary to change from one furnace classification to a different one.

Comment: Two commenters on the 2012 proposal disagreed with the EPA's proposal to allow secondary aluminum producers to switch furnace classification only after having one or more cycles of operation with clean charge before a control device can be turned off. The commenters stated that data from tests on two Alcoa furnaces show that there is no carryover of emissions from one charge to the next, and, by requiring operators to wait more than one cycle of operation before turning off the control device, the rule restricts a facility's ability to take timely action to repair an air pollution control device in the event of an unexpected equipment breakdown.

One of the commenters on the 2012 proposal described multiple instances of performance tests for two melting furnaces regarding emissions of batches operated with clean charge immediately after using dirty charge. The commenter provided summaries of the performance tests, and the tests show that emissions measured during the very next furnace cycle after using dirty charge were below the group 1 furnace emission limits.

In a comment on the supplemental proposal, one commenter stated that the requirement in the 2012 proposal to wait one or more operational cycles before turning off the control device when switching to clean charge in a furnace classification change is not supported by available data indicating that there is not ''carry-over'' of emissions from one batch to the next. The commenter cited furnace testing data from testing at Alcoa's Lancaster, Pennsylvania, facility.

One commenter stated that the preamble to the supplemental proposal does not state whether the EPA is proposing to remove the requirement in 40 CFR 63.1514 of the 2012 proposal to wait one or more charge-to-tap cycles using clean charge and without reactive flux addition before the performance test can be performed for a change from group 1 to group 2 operation. The commenter stated that, based on the proposed requirements, because the change of classification to a furnace without add-on control cannot be made until waiting the number of cycles operated during the performance test with clean charge (and without adding reactive flux), a classification change in this scenario could not be made in response to an unplanned event such as an unexpected baghouse malfunction. The commenter stated that facilities would be prevented from responding to unexpected baghouse system malfunctions by changing to group 2 operation. The commenter stated that similar restrictions are contained in 2012 proposed 40 CFR 63.1514 for changing from group 1 with add-on controls to group 1 without add-on controls. The commenter stated that the EPA provides no justification for requiring a facility to wait one or more charge-to-tap cycles before testing without add-on controls; therefore, the provision contained in the supplemental proposal cannot provide for reclassification during unplanned changes such as baghouse malfunction.

One commenter on the 2012 proposal asserted that if the EPA retains a flush cycle requirement in order to reclassify furnaces, each scenario should provide a time-based option for determining when the furnace can be reclassified. The commenter observed that the proposed sections 63.1514(a)(2)(i), (a)(4)(i), (c)(2)(i) and (c)(4)(i) allow either a number of charge-to-tap cycles or an operating time of 24 hours to elapse prior to furnace reclassification, and sections 63.1514(b)(2)(i) and (b)(4)(i) only provide a number of charge-to-tap cycles, and do not provide a time-based alternative. The commenter also suggested that instead of requiring ''1 or more charge to tap cycles, or 24 operating hours,'' the rule should require ''1 or more operating cycles or time period used in the performance test.'' The commenter explained that this language is more consistent with the description of ''furnace cycle'' used throughout Subpart RRR, and is more appropriate because a process cycle for some continuous operations is less than 24 hours.

One commenter on the 2012 proposal asked that the text for 40 CFR 63.1514(b)(2)(i) and 40 CFR 63.1514(b)(4)(i), ''Testing under this paragraph may be conducted at any time after the furnace has completed 1 or more charge to tap cycles with clean charge,'' be changed to ''Testing under this paragraph may be conducted at any time after the furnace has been tapped and has completed at least one (1) more additional cycle with clean charge.''

A commenter on the 2012 proposal observed that the proposed rule inconsistently uses the phrase ''additional tests,'' which appears to apply to operating modes for which the facility has already demonstrated compliance by conducting a valid performance test. The commenter noted that the February 16, 2012, Applicability Determination already specifies that testing is required to demonstrate compliance with emission limits for each operating mode, and requiring additional tests would add expense without any added environmental benefit.

Another commenter on the 2012 proposal observed that this proposed provision would require ''additional tests'' to demonstrate compliance with operating modes that already have valid performance tests. The commenter objected to the EPA requiring area sources to retest every 5 years. The commenter also objected to the EPA requiring that tilting melters at area sources in group 2 operating mode perform stack testing.

Response: In response to the comments and information provided by the commenters, the EPA agrees that it is not necessary to require one or more cycles with clean charge before a control device can be shut off under the change of classification procedures. As such, we have modified the final rule, accordingly.

The EPA has also removed the requirement that furnaces at area sources using group 2 as any alternative operating mode repeat the performance test every 5 years. Our use of the phrase ''additional performance tests'' in 40 CFR 63.1514 was not intended to apply to operating modes for which the facility has already demonstrated compliance by conducting a valid and relevant performance test. Accordingly, we have modified the final rule language in 40 CFR 63.1514 to make it clear that performance tests must be performed only if compliance for the operating mode has not already been demonstrated by a valid performance test and have clarified 40 CFR 63.1514 to indicate that ''additional tests'' are not required for operating modes for which the facility has already demonstrated compliance by conducting a valid performance test. In response to the commenter's objection to requiring a tilting melter to test when in group 2 mode, neither the proposed rule nor the final rule contains such a requirement for any tilting reverberatory furnace capable of completely removing furnace contents between batches.

4. What is the rationale for our final approach for changing furnace classification?

The final rule addresses an area of uncertainty under Subpart RRR by specifying rule provisions expressly allowing changes in furnace classification from one authorized operating mode to another, including from a controlled furnace operating mode to an uncontrolled furnace operating mode, subject to procedural and testing requirements, operating requirements and recordkeeping requirements. The final rule allows changes in furnace operating modes up to four times (including the four associated reversions) in a 6-month period. This frequency of changes in furnace operating modes is based on limited information submitted by industry on the number of furnaces changes that occur, taking into account the increased burden on the EPA and delegated states to oversee compliance for furnaces that repeatedly change their classification and associated emission standards and compliance requirements under Subpart RRR. The final rule allows sources to request additional changes in furnace operating mode by petitioning the permitting authority for major sources, or the Administrator for area sources.

E. Flow Rate Measurements and Annual Inspections of Capture/Collection Systems

1. What did we propose regarding flow rate measurements and annual inspections of capture/collection systems?

In the 2012 proposal, we proposed codifying in Subpart RRR our existing interpretation that annual hood inspections include flow rate measurements using EPA Reference Methods 1 and 2 in Appendix A to 40 CFR part 60. These flow rate measurements supplement the effectiveness of the required visual inspection for leaks, to reveal the presence of obstructions in the ductwork, confirm that fan efficiency has not declined and provide a measured value for air flow. Commenters on the 2012 proposal requested that the EPA allow flexibility in the methods used to complete the annual inspections of capture/collection systems stating that the use of volumetric flow measurement was often not necessary and Method 1 and 2 tests could be a cost burden for some facilities. Comments also indicated that routine, but less frequent, flow rate measurements could ensure that capture/collection systems are operated properly and suggested alternative methods of ensuring the efficiency of capture/collection systems.

Based on the comments received and our consideration of inspection needs, in the 2014 supplemental proposal we proposed additional options that provide more flexibility in how affected sources can verify the efficiency of their capture/collection system. Instead of annual Methods 1 and 2 testing, we proposed that sources may choose to perform flow rate measurements using EPA Methods 1 and 2 once every 5 years, provided that a flow rate indicator consisting of a pitot tube and differential pressure gauge is installed and used to record daily the differential pressure and to ensure that the differential pressure is maintained at or above 90 percent of the average pressure differential measured during the most recent Method 2 performance test series, and that the flow rate indicator is inspected annually. As another option to annual flow rate measurements using Methods 1 and 2, the EPA proposed to allow Methods 1 and 2 testing to be performed every 5 years provided that daily measurements of the revolutions per minute (RPM) of the capture and collection system's fan pr a fan motor amperage (amps) are taken, the readings are recorded daily, and the fan RPM or amps are maintained at or above 90 percent of the average RPM or amps measured during the most recent Method 2 performance test. Furthermore, we proposed that as an alternative to the flow rate measurements using Methods 1 and 2, the annual hood inspection requirements can be satisfied by conducting annual verification of a permanent total enclosure using EPA Method 204. We further proposed that as an alternative to the annual verification of a permanent total enclosure using EPA Method 204, verification can be performed once every 5 years if negative pressure in the enclosure is directly monitored by a pressure indicator and readings are recorded daily or the system is interlocked to halt material feed should the system not operate under negative pressure. We also proposed that readings outside a specified range would need to be investigated and steps taken to restore normal operation, and that pressure indicators would need to be inspected annually for damage and operability.

2. What changed since proposal regarding flow rate measurements and annual inspections of capture/collection systems?

The final rule contains modified monitoring requirements in 40 CFR 63.1510(d) to allow the use of non-pitot based flow rate measuring equipment (*i.e.*, hotwire anemometer, ultrasonic flow meter, cross-duct pressure differential sensor, venturi pressure differential monitoring or orifice plate) equipped with an associated thermocouple and automated data logging software and associated hardware. These monitoring provisions provide the secondary aluminum production source category with flexibility and less costly alternatives to annual inspections using Methods 1 and 2 and Method 204 while also ensuring the proper operation of capture and collection systems.

3. What key comments did we receive regarding flow rate measurements and annual inspections of capture/collection systems?

Comment: One commenter on the 2012 proposal contended that the EPA should continue to allow affected sources flexibility in methods used to complete annual inspections of capture/collection and closed vent systems. The commenter stated that the proposed rule would add a volumetric flow measurement requirement, which is unnecessary in many cases, to demonstrate proper operation of the capture/collection and closed vent system. The commenter contended that current rule flexibility allows sources to utilize monitoring methods that are appropriate and cost effective for their operations and equipment; this choice of monitoring method is included in an approved OM&M plan certified by the owner or operator. The commenter also noted that the additional cost burden on facilities to perform a Method 1 and Method 2 measurement was not considered by the EPA in the rulemaking process. The commenter estimated that EPA Methods 1 and 2 will require the facility to hire an outside contractor and incur costs of more than $3,000 per unit. The commenter recommended that the Agency should continue to allow affected sources the ability to determine the best inspection methods to verify that capture/collection and closed vent systems meet operating requirements.

One commenter on the 2012 proposal discussed 40 CFR 63.1510(d)(2), stating that while in agreement with the need to routinely perform volumetric flow rate measurements, after negotiation with the EPA, a determination was made that a frequency of every 30 months was sufficient, as documented in a 2009 consent decree resolving a federal enforcement action against the company. The commenter asserted that volumetric flow rate measurement is a costly procedure, performed by outside contractors costing about $2,000 a day, and cost per inspection will vary by the number of systems to be checked. The commenter noted that for the commenter's facilities, approximately fifty rechecks have been performed to comply with the requirements of the consent decree or due to new stack testing. The commenter stated that all have demonstrated that each system is operating in accordance with the requirements in 40 CFR 63.1506(c). According to the commenter, this shows that there is no need to conduct this flow measurement more than once every 30 months. The commenter objected to the requirement to perform volumetric flow measurements on each hood. The commenter stated that when multiple hoods are manifolded together, it is not always possible to meet Method 1 requirements on all hoods to be measured, and at times it is necessary to measure the main trunk and arrive at the volumetric flow rate for an individual hood by calculation. According to the commenter, this method has been used repeatedly and submitted to the EPA and state agencies with stack test reports, and has been accepted. The commenter requested that the EPA clarify that the proposed language does not preclude this approach, or modify the proposed language to include such clarification.

Response: Verification of the flow rate of the exhaust stream that is directed to the control device is necessary to assure the efficiency of the control system and to ensure continuous compliance with the emission standards between performance tests. In addition, owners or operators of area source facilities are not required to conduct periodic performance tests and this requirement may help detect leaks and defects in the duct work sooner than they otherwise would be found. The EPA is adopting the requirements as proposed in the 2012 and 2014 proposals, including options that provide flexibility in how affected sources can verify their flow rates.

Instead of annual Methods 1 and 2 testing, flow rate measurements using EPA Methods 1 and 2 can be performed once every 5 years, provided that a flow rate indicator consisting of a pitot tube and differential pressure gauge is installed and used to record daily the differential pressure, that the differential pressure is maintained at or above 90 percent of the pressure differential measured during the most recent Method 2 performance test series, and that the flow rate indicator is inspected annually. As another option to annual flow rate measurements using Methods 1 and 2, the EPA is allowing Methods 1 and 2 to be performed every 5 years provided that daily measurements of the capture and collection system's fan RPM are made, that the readings are recorded daily, and that the RPM are maintained at or above 90 percent of the RPM measured during the most recent Method 2 performance test series. Other options for annual flow rate measurements using Methods 1 and 2 that we are allowing are annual measurements of the face velocity of booth-type hoods, or installation of static pressure measurement in the duct at the hood exit, provided that the values obtained for these measurements are at or above 90 percent of the values measured during the most recent Method 2 performance test series. Further, we are allowing that as an alternative to the flow rate measurements using Methods 1 and 2, the annual hood inspection requirements can be satisfied by conducting annual verification of a permanent total enclosure using EPA Method 204.

We are further allowing that, as an alternative to the annual verification of a permanent total enclosure using EPA Method 204, verification can be performed once every 5 years if negative pressure in the enclosure is directly monitored by a pressure indicator and readings are recorded daily or the system is interlocked to halt material feed should the system not operate under negative pressure. We are also requiring that readings outside a specified range be investigated and steps taken to restore normal operation, and that pressure indicators would need to be inspected annually for damage and operability. We are also allowing non-pitot based flow rate measuring equipment (*i.e.*, hotwire anemometer, ultrasonic flow meter, cross-duct pressure differential sensor, venturi pressure differential monitoring or orifice plate) equipped with an associated thermocouple and automated data logging software and associated hardware as a sufficient monitoring system for compliance with this rule.

The 2009 Consent Decree at paragraph 122 states clearly that each company is responsible for achieving and maintaining complete compliance with all applicable federal laws and regulations, and compliance with the Consent Decree does not necessarily mean compliance with the Clean Air Act or implementing regulations. Further, the Consent Decree does not limit the EPA's authority to revise subpart RRR.

The commenters assert that annual measurements of flow rates will result in additional costs to conduct EPA Methods 1 and 2 testing. Because in EPA's view the existing requirements prior to this rulemaking required annual testing, we disagree that these costs represent a new burden. See Memorandum, Michael Alushin, EPA Office of Compliance Enforcement Assurance, to EPA Regional Air Directors, ''Compliance with ACGIH Ventilation Manual,'' August 16, 2006, which is in this rulemaking docket.

Comment: In a comment on the supplemental proposal, one commenter stated that in the supplemental proposal, the EPA would allow several alternatives to an annual Methods 1 and 2 flow rate measurement including the option to verify a permanent total enclosure every five years and directly monitor negative pressure, which they support. The commenter stated that there appears to be an inconsistency in proposed sections 63.1506(c) and 63.1510(d). The commenter stated that 40 CFR 63.1506(c)(1) requires capture and collection systems to meet ''engineering standards for minimum exhaust rates'' from the ACGIH Manuals, but the supplemental proposal allows an operator to ensure compliance with 40 CFR 63.1506(c) by verifying a permanent total enclosure by Method 204, which verifies the facial velocity and that an inward flow is maintained at all openings, but does not include a measurement of exhaust rates. The commenter stated that the ACGIH Manuals do not provide minimum exhaust rates for all types of capture and collection systems used by the secondary aluminum industry; for example, some capture and collection systems are not typical ventilation hoods and are more appropriately described in the ACGIH Manuals as ''Moderate Control Total Enclosures'' and, for these systems, the manual does not provide minimum exhaust rates, but rather describes appropriate velocities to maintain through openings in the enclosure. The commenter stated that to the extent the manuals are referenced in the final rule, the EPA should revise 40 CFR 63.1506 to remove the reference to ''minimum exhaust rates'' and require the system to be designed and monitored to meet ''applicable engineering standards'' as follows:

''Design and install a system for the capture and collection of emissions to meet the applicable engineering standards for minimum exhaust rates as published by the American Conference of Governmental Industrial Hygienists in *Industrial Ventilation: A Manual of Recommended Practice* 23rd or 27th edition (ACGIH Guidelines) (incorporated by reference in § 63.1502 of this subpart).''

Response: Because the ACGIH guidelines also contain inlet velocities as pointed out by the commenter, 40 CFR 63.1506(c)(1) of the final rule now reads ''Design and install a system for the capture and collection of emissions to meet the engineering standards for minimum exhaust rates or inlet facial velocities as contained in the ACGIH Guidelines.''

Comment: In a comment on the supplemental proposal, one commenter stated that they concur with the flexibility that the EPA provides in 40 CFR 63.1510(d)(2)(ii) and (iii) to allow 5-year flow rate testing measurements to supplant the annual testing requirement, if a pitot tube and differential pressure gauge are installed and monitored in the hooding (ii), or if fan RPM's are tracked and recorded (iii). The commenter stated that, however, based on real world experience with the flow verification of permanently installed hooding devices, there are other options that should also be included that would provide the same level of protectiveness; two options are:

Option 1. Install a pressure tap in the duct just above the hood exit point, and monitor pressure similar to the pitot tube. The commenter stated that this is simpler than a pitot tube installation, less prone to clogging, and has been effectively used at an existing location. According to the commenter, the signal will equal pressure loss in the hood entrance plus velocity pressure in the duct, and generally be proportional to the velocity in the duct squared. The commenter stated that at 3,000 ft/min duct velocity it will be similar to the pitot tube at approximately 0.70 inches water gauge, that calibration of differential pressure readings can be done by EPA Methods 1 and 2 flow testing, and that it is easier to install in a duct since no straight run is required.

Option 2. If the hood has a straight face (*i.e.*, booth type), face velocity measurements could be made over the face of the hood and averaged to determine velocity. Measured face velocity could be compared to calculated data vs. EPA Methods 1 and 2 on a 5-year frequency. The commenter provided the following comments on this option:

- No negative flow points should be observed, since this will allow smoke to escape the hood.
- This will not work for canopy or irregularly shaped hoods.
- Low velocities require an appropriate measurement device.
- Cannot be done while material is being loaded into hood.

The commenter requested that new paragraphs (iv) and (v) be added to 40 CFR 63.1510(d)(2) for the inclusion of options 1 and 2 above.

In a comment on the supplemental proposal, one commenter objected to the EPA's supplemental proposal to the extent that it only provides two methods to measure flow to avoid annual inspection for permanently installed capture, collection, and transport systems (*i.e.*, hoods). The commenter stated that Table 3 of the supplemental proposal allows a source to delay annual inspections for capture devices to once every 5 years, if the source monitors flow through daily pressure differential measurements or fan RPM measurements. The commenter stated that they support the recommendations and rationale of the Aluminum Association (TAA) to include additional flow monitoring alternatives to avoid annual inspections, including installation of a pressure tube above hood exit points, face velocity measurements (for straight face (booth type) hoods) and by direct observation of smoke in the hood by a method 22 or similar test. The commenter stated that by including additional flow-monitoring alternatives, the EPA would allow sources the option to pick the most reliable and least burdensome flow monitoring method that fits the type of hood used to capture emissions at the source.

In a comment on the supplemental proposal, one commenter stated that the alternative to the annual capture/collection and closed vent system inspection requirements at 40 CFR 63.1510(d)(2)(ii) is unreasonably restrictive and should not be limited to using conventional pitot tube and a differential pressure gauge equipment to qualify for the once in 5 year alternative. The commenter recommended that the EPA further amend 63.1510(d)(2) to permit the use of non-pitot based flow measuring equipment and to permit volumetric flow measurements to be automated using available software and hardware.

Response: The proposed alternatives of annual measurements of face velocity for straight face (booth-type) hoods using a hot-wire anemometer, or installation of a pressure tap in the duct just downstream of the hood exit point, and monitoring pressure, as suggested by the commenters, are acceptable. We also agree that non-pitot based flow rate measuring equipment (*i.e.*, hotwire anemometer, ultrasonic flow meter, cross-duct pressure differential sensor, venturi pressure differential monitoring or orifice plate) equipped with an associated thermocouple and automated data logging software and associated hardware is a sufficient monitoring system for compliance with this rule. We are modifying the rule language to accommodate these monitoring options.

4. What is the rationale for our final approach for flow rate measurements and annual inspections of capture/collection systems?

Based on the rationale presented in the preamble to the 2012 proposed rule, the final rule codifies in subpart RRR our interpretation that annual inspections of capture and collection systems include flow rate measurements using EPA Reference Methods 1 and 2 in Appendix A to 40 CFR part 60. However, based on the public comments regarding additional flow measurement technologies and our responses to those comments presented in the previous section of this preamble, the final rule also includes additional options that provide more flexibility in how affected sources can verify the efficiency of their capture/collection system.

F. Compliance Dates

1. What compliance dates did we propose?

In the 2012 proposal, the EPA proposed that owners or operators of existing affected sources comply with the proposed amendments within 90 days of the publication of the final rule in the **Federal Register**. Commenters stated that the proposed 90-day compliance deadline was insufficient for sources to comply with certain provisions. They maintained that the rule changes would require operational planning, maintenance planning, reprogramming of data acquisition systems, design and installation of hooding equipment and/or negotiations with permitting authorities to gain performance test plan approvals (with provisions to minimize fugitive emissions during testing in place of capture hoods). They pointed out that facilities that choose to design and install capture hoods for performance testing will need time to design and complete these installations, conduct initial performance testing and modify their operations, charge materials and/or products to ensure compliance. Some rule changes, furnace classification changes, HF testing and testing uncontrolled furnaces for example, would require revisions to OM&M plans as well as to permits to include newly established operating parameters in cases where changes to furnace classifications are made. Commenters stated that compliance with HF emission standards that may affect choice of flux materials, daily calculation of HF emissions and compliance with SAPU limit that will require reprogramming of data systems to include HF and/or fluoride containing flux composition data would also require time to be researched, selected, purchased, financed and installed. Commenters suggested compliance deadlines ranging from 2 to 3 years.

In the 2014 supplemental proposal, the EPA agreed with commenters that the proposed 90-day compliance deadline was insufficient for sources to comply with certain proposed provisions and proposed extended compliance periods. The EPA proposed a 180-day compliance period for the revisions listed in 40 CFR 63.1501(d). For the amendments to include HF emissions (in 40 CFR 63.1505(i)(4) and (k)(2)), the testing of existing uncontrolled furnaces (§§ 63.1512(e)(4), (e)(5), (e)(6) and (e)(7)), and changing furnace classification (40 CFR 63.1514), the EPA proposed a compliance date of 2 years after promulgation.

2. What compliance dates changed since proposal?

As noted above, we adjusted some compliance dates in our supplemental proposal. We received no comments or information following the supplemental proposal that warranted any changes to the compliance dates proposed in the supplemental proposal. As proposed, compliance with the provisions listed in 40 CFR 63.1501(d) is required 180 days following publication of the final rule while compliance with the provisions listed in 40 CFR 63.1501(e) is required 2 years following publication of the final rule.

3. What key comments did we receive related to compliance dates?

Comment: One commenter on the 2012 proposal agreed with the 180 day time period for startup for new sources' initial performance tests. However, the commenter stated that due to the integration of modern facilities, running a regulated unit at full capacity may be affected or constrained by downstream equipment, market constraints or other technical issues beyond the control of the facility. The commenter stated that the current provisions provide relief only through the administrative order process, which is costly and arduous. The commenter requested that the EPA include a provision to petition for an extension of the deadline if a test is not feasible within the allowed time period to allow time for the facility to reach full capacity.

Response: As proposed in the supplemental proposal, the final amendments increase the time period for initial compliance testing for a new source from 90 days to 180 days. The commenter did not provide data or other specific documentation to support a conclusion that an affected source cannot reach full capacity within 180 days of startup.

Comment: Two commenters on the 2012 proposal asked the EPA to clarify in the rule that the new HF requirements are not effective until ''the next scheduled performance test after the effective date of the final rule.'' The commenters observed that in the proposal preamble the HF testing requirement, and presumably the HF limit, was said to become effective ''at the next scheduled performance test after the effective date of the final rule.'' The commenters noted that the regulatory language does not make this clear, as 40 CFR 63.1501 states that owners or operators must comply with the HF limit and the HF testing requirement within 90 days after promulgation.

In comments on the supplemental proposal, two commenters requested that the EPA clarify that the intent of the proposed language is to not require testing for HF on existing major source uncontrolled group 1 furnaces within 2 years of the final rule publication date but at the next scheduled 5 year required stack test following publication of the final rule.

One commenter on the 2014 supplemental proposal stated that they interpret the proposed language of 40 CFR 63.1501(e) to indicate that the effective date of the new HF standard and the new requirements for testing existing uncontrolled group 1 furnaces is 2 years from final rule promulgation and that they further understand that testing to demonstrate compliance with the newly effective provisions can be done on a timeline consistent with the existing 5-year performance testing cycle established using the existing 40 CFR 63.1511(e) provision such that the compliance demonstration is made at the next scheduled performance test after the effective date of the final rule. The commenter stated that this is true even if the next scheduled performance test on the normal 5-year testing cycle is outside the 2-year compliance window. The commenter provided an example to illustrate their interpretation of the compliance date requirements.

Two commenters suggested the following revision to 40 CFR 63.1512(e)(4):

''When testing an existing uncontrolled furnace, the owner or operator must comply with the requirements of either paragraph (e)(4)(i) or paragraph (ii) of this section at the next performance test required by 40 CFR 63.1511(e).''

The commenters also requested clarification of when HF emissions must be included in SAPU calculations. According to the commenters, furnaces at some facilities are on different testing schedules, which mean that some furnaces will become subject to the HF limit and HF SAPU calculation before others. The commenters assumed each furnace would be added to the HF SAPU calculation when tested, but the commenters requested that the EPA clarify this in the final rule.

Response: Although the final rule is effective upon promulgation pursuant to CAA section 112(d)(10), the commenters are correct that the final rule requires HF testing at the next scheduled performance test if the test occurs 2 years or more after the final rule is published in the **Federal Register**. We clarified in the final rule that the HF requirements apply to the next scheduled performance test if the next scheduled performance test occurs 2 years or more after the final rule is published in the **Federal Register**. The final rule also clearly provides that each furnace will be added to the HF SAPU calculation following the initial performance test for HF for the furnace, or for a representative furnace tested, to determine HF emissions from the furnace.

Comment: Several commenters on the 2012 proposal disagreed with the proposed ninety-day compliance date. Two commenters stated that requiring compliance only 90 days after promulgation is unnecessary and does not provide sufficient time. One commenter suggested that due to engineering and management constraints, the period be extended to 180 days, which would allow the industry to make necessary changes. The commenter noted potential component lead-times and permitting procedures outside of the control of operators. Another commenter recommended 2 to 3 years for compliance, assuming the EPA promulgates corrections and clarifications that require a compliance window.

Two commenters on the 2012 proposal maintained the rule changes will require operational planning, maintenance planning, reprogramming of data acquisition systems, design and installation of hooding equipment and/ or negotiations with permitting authorities to gain performance test plan approvals (with provisions to minimize fugitive emissions during testing in place of capture hoods). One commenter stated that facilities that choose to design and install capture hoods for performance testing will need time to design and complete these installations, conduct initial performance testing and modify their operations, charge materials and/or products to ensure compliance.

One commenter on the 2012 proposal stated that some facilities will also need to prepare and submit revised OM&M plans that incorporate changes related to bag leak detector maintenance, lime feeder calibrations, metal liquid depth monitoring and/or procedures for changing furnace classifications. The commenter noted that under the proposed rule, these revised OM&M plans could not be implemented until 60 days after submittal to the permitting authority, meaning that companies would effectively have only 30 days to define their compliance approach and submit revised OM&M plans. The commenter concluded that this 90-day compliance timeline is neither practicable nor reasonable.

One commenter on the 2012 proposal recommended a minimum of one year to implement the controls and reporting requirements. The commenter stated that any new technology requirements or installation of new or modification of existing emission controls would impose added costs, and 90 days did not provide an adequate opportunity for additions to be researched, selected, purchased, financed, and installed. The commenter also stated that the Subpart ZZZZZZ rule allowed two years and that would be preferable, but a period of no less than twelve months would be fair and acceptable. The commenter also suggested the same delay should apply to the development and filing of a written OM&M plan.

One commenter on the 2012 proposal stated that the following provisions cannot be met within 90 days due to the possible need for ductwork revisions and further stack testing: §§ 63.1505(a), 63.1505(i)(4), 63.1505(k), 63.1510(b), 63.1510(d)(2), 63.1510(o)(l)(ii), 63.1512(e)(l), 63.1512(e)(2), and 63.1512(e)(4). The commenter stated it is not reasonable to begin work on these provisions immediately since they will be subject to further comment and hopefully significant revision in the final rule.

Two commenters on the 2012 proposal requested a 3-year compliance timeline for the provisions that result in changes in operations and/or operation practices, or impact control technology and monitoring requirements at existing sources. One commenter stated that a 3-year compliance date would allow smaller producers opportunity to budget for large capital and resource costs. The commenters suggested a 3-year compliance date for the following provisions:

- § 63.1505(a)(1), emission limits applicable to SSM periods;
- § 63.1505(i)(4), compliance with HF emission standards that may affect choice of flux materials;
- § 63.1505(k)(2), daily calculation of HF emissions and compliance with SAPU limit that will require reprogramming of data systems to include HF and/or fluoride containing flux composition data;
- § 63.1510(b)(5), procedures in OM&M plan for process and control device parameters that require addition of lime injection rates that may require new or modified equipment to determine rates or calibrate lime mass feed rate and will require lime injection rate to be established during next scheduled performance test; 63.1510(b)(5), requirements and scope for capture/collection system inspections on controlled emission units;
- § 63.1510(i)(4), monthly lime injection rate verification that may require new or modified equipment to allow verification of lime mass feed rate;
- § 63.1510(j)(4), recordkeeping (and associated training of operating personnel) for solid flux added intermittently;
- § 63.1510(n)(1), monitoring molten metal level of sidewell furnaces that will require selection, purchase, installation, testing and maintenance procedures for new equipment;
- § 63.1512(e)(1) and (e)(4), deletes ''furnace exhaust outlet'' as compliance basis and imposes new compliance demonstration requirements for uncontrolled furnaces based on temporary capture hoods, reduced emission limit equal to 67 percent of the existing standard or procedures to minimize fugitive emissions during testing negotiated with permitting authority;
- § 63.1512(p)(2), record lime injection rates during the three test runs that will require lime injection rate to be established during next scheduled performance test; some existing systems do not have a viable means for weighing

mass rate of lime being injected and new or modified equipment will be required;

• § 63.1513(e)(1), (e)(2), and (e)(3), co-controlled units added to SAPU calculation that may require revision of OM&M plan and reprogramming of data systems used to track and record SAPU calculations; and

• § 63.1514, requirements for changing furnace classifications which differ from those in current Title V permits, and will need revision after owners and operators establish compliance conditions and gather performance data.

One commenter on the 2012 proposal suggested that the effective date for the revised 40 CFR 63.1511(b)(1) language would need to be ''at the next required performance test.'' The commenter asserted that the proposed provision changes the required test conditions for some operations and could not be met by the proposed effective date of 90 days.

One commenter on the 2012 proposal asserted that the EPA is not required to impose the 90-day compliance period on area sources because promulgation of section 112(f) standards is not required based on the EPA's findings that the MIR for secondary aluminum area sources, based on actual emissions, was 0.4-in-1 million. The commenter stated that the EPA may grant up to a 3-year compliance deadline for area sources. The commenter contended that, as a practical matter, the EPA should provide a compliance period for area sources commensurate with the several new administrative requirements for which more than 90 days are required to achieve implementation. The commenter stated that, due to the revisions required for facility operations and the time constraints for revision and approval of an OM&M plan, the EPA should grant at least a 1-year compliance period. The commenter described potential time constraints.

In a comment on the 2014 supplemental proposal, one commenter stated that compliance deadlines for new standards developed under the section 112 program must be set for a date that is as expeditious as practicable, but no later than 3 years after rule implementation. The commenter stated that the EPA is not required to impose the 180-day compliance period on area sources because promulgation of section 112(f) standards is not required when the residual cancer risk under the existing MACT standards are not equal to or greater than 1-in-1 million. The commenter stated that because of the low MIR from area sources (0.6-in-1 million), the EPA was not required to promulgate standards under 112(f); accordingly, the EPA may grant up to a three-year compliance deadline for area sources. The commenter stated that the EPA should provide a compliance period for area sources that is commensurate with the several new administrative and monitoring requirements for which more than 180 days are required to achieve full implementation. The commenter provided the following example to illustrate the need for a longer compliance period: Additional monitoring requirements for capture and collection systems proposed in 40 CFR 63.1510(d)(2) may require installation of flow rate or pressure monitoring equipment; these changes, and others proposed in the 2012 proposal, may require submittal of a revised OM&M plan to the permitting authority; among the revisions to the OM&M plan under the 2012 proposal are new requirements for the inspection of capture and collection systems and additional performance testing requirements; the owner or operator may not begin operating under this revised OM&M plan until approval is received from the permitting authority, or 60 days, whichever is sooner. The commenter stated that, even to the extent that the 2012 proposal provides for default approval of OM&M plans after 60 days, this only leaves the source with 120 days to install monitoring equipment and implement the plan; this time frame is inappropriate. The commenter stated that, due to the revisions required for facility operations and the time restraints for revision and approval of an OM&M plan, the EPA should grant at least a 1-year compliance period.

Response: As discussed in the 2014 supplemental proposal, the EPA agrees with the commenters on the 2012 proposal that the proposed 90-day compliance deadline is insufficient for sources to comply with certain provisions of the final rule and is finalizing extended compliance periods. The final compliance dates are the same as those proposed in the 2014 supplemental proposal, on which we received only one comment. As these amendments clarify existing requirements, and based on the lack of supporting information for the commenter's conclusory assertion that 2 years is insufficient, we do not agree that any of the revisions warrant an extension beyond 2 years to a 3-year compliance period. Regarding the commenter's concern that small producers would need 2 to 3 years to budget for large capital and resource costs, we determined in our economic and small business analysis (see section VI.C of this action) that 28 entities will incur costs associated with this rule and, of the 28 entities, nine of them are small based on the definition of the Small Business Administration. Of these nine small businesses, all are estimated to experience a negative cost (*i.e.*, a cost savings) as a result of the final rule. Therefore, we do not agree that more than a 2-year compliance period is necessary.

As a result of comments on the 2012 proposal, the final rule does not contain the 60-day approval period for OM&M plans. Therefore, the industry will have the full 180 days for compliance rather than a 120-day compliance period as was a concern of one commenter. The final rule retains the 2-year compliance period for those requirements listed in 40 CFR 63.1501(e). The final rule does not change the requirement that existing major sources conduct performance tests every 5 years.

The EPA disagrees that additional time is needed to comply with the changes related to SSM. The Court issued a decision on December 19, 2008, to vacate SSM provisions in the General Provisions. *Sierra Club* v. *EPA*, 551 F.3d 1019 (D.C. Cir. 2008). The EPA issued a letter on July 22, 2009, addressing the impact of the decision. The court mandate implementing the *Sierra Club* decision was issued on October 16, 2009, at which time the SSM provisions were clearly no longer in effect. As explained in the July 2009 memo, SSM provisions in specific subparts, such as those in Subpart RRR, were directly affected by the court decision. In addition, amendments to Subpart RRR were proposed on February 14, 2012, at which time secondary aluminum facilities were put on notice of the specific amendments to Subpart RRR in response to the Court's vacatur of the SSM provisions. Thus, facilities have had ample notice that the EPA would make the SSM rule changes. As a result, the SSM-related rule changes are effective upon promulgation of the final rule. See also discussion in section III.C of this preamble.

Comment: Two commenters on the 2012 proposal requested changes to the new hooding requirement in 40 CFR 63.1512(e)(4), requiring compliance ''at the next required performance test'' even if the test must be performed ''90 days from promulgation of the final rule'' [§ 63.1501(d)]. The commenters explained that this compliance deadline may be acceptable for facilities that are not required to conduct performance testing in the first few years following promulgation of the final rule, but other facilities are on a testing cycle that would require testing soon after promulgation and these facilities may not have time to install hoods and/or modify operating practices within the allotted 90 days. The commenters stated that according to the NESHAP General Provisions, test protocols must be submitted 60 days before a compliance test, so facilities required to test early in 2013 would have as little as 30 days after the final rule to address the new hooding requirements and other requirements of the final rule before submitting a test plan. The commenters did not believe that this timeline is practicable or reasonable. The commenters requested the EPA to revise the compliance date for capture hoods on uncontrolled furnaces (in § 63.1512 (e)(4)) to say: ''three years after the final promulgation date or at the next required performance test, whichever date is later.''

Response: The EPA agrees with the commenters that the time available for owners or operators of facilities with performance testing required under 40 CFR 63.1512(e)(4) and occurring near the proposed 90-day compliance deadline would be insufficient. As described above, in the final rule the requirement to account for unmeasured emissions during uncontrolled group 1 furnace performance testing applies to testing beginning 2 years after publication of the final rule in the **Federal Register**. Therefore, a source with their next required performance test of an uncontrolled group 1 furnace occurring at least 2 years after promulgation would have to comply with the testing provisions in 40 CFR 63.1512(e)(4). A source with their next required performance test of an uncontrolled group 1 furnace occurring 1 year (or any period less than 2 years) after promulgation would not be required to do so until the subsequent performance test. As these amendments clarify existing requirements, and based on the lack of supporting information for the commenter's conclusory assertion that 2 years is insufficient, we do not agree that any of the revisions warrant an extension beyond 2 years to a 3-year compliance period.

4. What is the rationale for our final approach related to compliance dates?

The rationale for the compliance dates is provided in the preamble to the supplemental proposal and is re-iterated in the responses to comments in the previous section of this preamble. The final rule specifies the compliance dates for the new requirements. Compliance with the provisions listed in 40 CFR 63.1501(d) is required 180 days following publication of the final rule. Rule changes specified in § 63.1501(e)—furnace classification changes, HF testing and testing uncontrolled furnaces—require more time, and the final rule provides 2 years following publication of the final rule for compliance.

V. Summary of Cost, Environmental and Economic Impacts and Additional Analyses Conducted

A. What are the affected sources?

We estimate that there are 161 secondary aluminum production facilities that will be affected by this final rule. We performed risk modeling for 155 of these sources (52 of the 53 major sources and 103 of the 108 area sources). Six facilities that are subject to the Secondary Aluminum NESHAP were not included in the risk assessment input modeling files. The facilities that were not included in the risk assessment input files included one major HAP source and five area HAP sources. The major HAP source was not included because the secondary aluminum equipment at the source consists of group 2 furnaces, for which the EPA did not have HAP emissions estimates. The five area sources were not included because they had no equipment subject to D/F emission standards, which are the only standards in the NESHAP applicable to area sources. We estimate that nine secondary aluminum facilities have co-located primary aluminum operations. The affected sources at secondary aluminum production facilities include new and existing scrap shredders, thermal chip dryers, scrap dryer/delacquering kiln/decoating kilns, group 2 furnaces, sweat furnaces, dross-only furnaces, rotary dross cooler and secondary aluminum processing units containing group 1 furnaces and in-line fluxers.

B. What are the air quality impacts?

The RTR analysis conducted for this rule does not support increasing the stringency of the numerical emissions limits. This final rule clarifies how uncontrolled furnaces are to conduct emissions testing, revises the monitoring requirements for annual inspection of capture/collection systems and makes other changes that correct and clarify rule requirements and provisions. These final amendments are not expected to achieve appreciable reductions in emissions, although the final requirements for testing uncontrolled furnaces could result in some unquantifiable emission reduction. Therefore, no quantifiable air quality impacts are expected. However, these final amendments will help to improve compliance, monitoring and implementation of the rule.

C. What are the cost impacts?

The total cost of the final amendments are the same as we described in the supplemental proposal. We conservatively estimate the total cost of the final amendments to be $1,711,000 per year (in 2011 dollars). However, depending on assumptions used for the costs for installing temporary hooding for uncontrolled furnaces, the estimate of total annualized costs could range from $611,000 to $2,871,000 per year. Our estimate for the source category includes an annualized cost of $1,200,000 to $3,460,000 for installing hooding that meets ACGIH guidelines for testing uncontrolled furnaces, assuming that 107 furnaces choose that option (rather than assuming an 80-percent capture efficiency for their existing furnace exhaust system). We believe that a number of these 107 furnaces will choose to apply the 80-percent assumption rather than install temporary hooding. Our estimates do not include deductions for the exclusion of existing round top furnaces as provided in the final rule. Therefore, these total cost estimates are considered conservative (more likely to be overestimates rather than underestimates) of the total costs to the industry. Our estimates of total costs also include an annualized cost of $11,000 for testing for HF on uncontrolled furnaces that are already testing for HCl. Finally, we estimate cost savings of $600,000 per year for furnaces that change furnace operating modes and turn off their control devices. Our estimate of savings is based on 50 furnaces turning off their controls for approximately 6 months every year. This savings reflects the cost of testing (to demonstrate these furnaces remain in compliance with emission limits) minus the savings realized from operating with the control devices turned off.

We estimate that 57 facilities will be affected and that the cost per facility ranges from negative $36,000 (a cost savings) per year for a facility changing furnace operating modes to $216,500 per year for a facility installing hooding for testing.

The estimated costs are explained further in the document titled, *Cost Estimate for Rule Changes to Secondary Aluminum NESHAP,* which is available in the docket for this action.

D. What are the economic impacts?

We performed an economic impact analysis for the amendments in this final rule. This analysis estimates impacts based on using annualized cost-to-sales ratios for affected firms. For the 28 parent firms affected by this final rule, the cost-to-sales estimate for each parent firm is less than 0.1 percent. For more information, please refer to the document titled, *Economic Impact Analysis for the Secondary Aluminum Supplemental Proposal,* which is available in the docket.

E. What are the benefits?

We do not anticipate any significant reductions in HAP emissions as a result of these final amendments. However, we think that they will help to improve the clarity of the rule, which can improve compliance and minimize emissions. Certain provisions also provide operational flexibility with no increase in HAP emissions.

F. What analysis of environmental justice did we conduct?

We did not conduct an assessment of risks to individual demographic groups for this rulemaking. However, we did conduct a proximity analysis for both area and major sources, which identifies any overrepresentation of minority, low income or indigenous populations near facilities in the source category. The results of the proximity analyses suggested there are a higher percentage of minorities, people with low income, and people without a high school diploma living near these facilities (*i.e.,* within 3 miles) compared to the national averages for these subpopulations. However, the risks due to HAP emissions from this source category are low for all populations (*e.g.,* inhalation cancer risks are less than 1-in-1 million for all populations and non-cancer HIs are less than 1). We note that we do not expect this final rule to achieve reductions in HAP emissions. We conclude that this rule will not have disproportionately high and adverse human health or environmental effects on minority or low-income populations because it does not affect the level of protection provided to human health or the environment. However, the final rule will provide additional benefits to these and all demographic groups by improving the compliance, monitoring and implementation of the NESHAP.

G. What analysis of children's environmental health did we conduct?

This action is not subject to Executive Order 13045 (62 FR 19885, April 23, 1997) because it is not economically significant as defined in Executive Order 12866, and because the Agency does not believe the environmental health risks or safety risks addressed by this action present a disproportionate risk to children. The risk assessment report, *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule,* which is available in the docket, estimated that no one is exposed to an inhalation cancer risk at or above 1-in-1 million or a chronic noncancer TOSHI greater than one due to emissions from the source category. The *2015 Environmental Justice Screening Report for Secondary Aluminum Major Sources and the 2015 Environmental Justice Screening Report for Secondary Aluminum Area Sources,* also available in the docket, indicate the percentages for all demographic groups exposed to various risk levels, including children, are similar to their respective nationwide percentages. All groups are exposed to cancer risks below 1-in-1 million and HIs less than 1 due to inhalation exposure to HAP emissions from this source category.

VI. Statutory and Executive Order Reviews

Additional information about these statutes and Executive Orders can be found at *http://www2.epa.gov/laws-regulations/laws-and-executive-orders.*

A. Executive Orders 12866: Regulatory Planning and Review and Executive Order 13563: Improving Regulation and Regulatory Review

This action is not a significant regulatory action and was therefore not submitted to the Office of Management and Budget (OMB) for review.

B. Paperwork Reduction Act (PRA)

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 requirements are not enforceable until OMB approves them.

We are establishing new paperwork requirements for the Secondary Aluminum Production source category to improve enforcement of and compliance with 40 CFR part 63, subpart RRR. The new requirements are in the form of recordkeeping and reporting for furnace classification changes and recordkeeping with regard to verification of lime injection rates. New monitoring requirements include testing for HF, and testing related to furnace classification changes. The information requirements are based on notification, recordkeeping, and reporting requirements in the NESHAP General Provisions (40 CFR part 63, subpart A), which generally apply to all operators subject to Part 63 national emissions 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.

We estimate 161 regulated entities are currently subject to Subpart RRR. The annual monitoring, reporting and recordkeeping burden for this collection (averaged over the first 3 years after the effective date of the rule) for these amendments to Subpart RRR is estimated to be $2,990,000 per year. This includes 1,694 labor hours per year at a total labor cost of $162,000 per year, and total non-labor capital and operation and maintenance (O&M) costs of $2,828,000 per year. The total burden for the federal government (averaged over the first 3 years after the effective date of the rule) is estimated to be 271 labor hours per year at an annual cost of $12,231. Burden is defined at 5 CFR 1320.3(b).

An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. The OMB control numbers for the EPA's regulations in 40 CFR are listed in 40 CFR part 9. 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 (RFA)

I certify that this action will not have a significant economic impact on a substantial number of small entities under the RFA. The small entities subject to the requirements of this action are small businesses. We determined in the economic and small business analysis that, using the results from the cost memorandum, 28 entities will incur costs associated with the final rule. Of these 28 entities, nine of them are small. Of these nine, all of them are estimated to experience a negative cost (i.e., a cost savings) as a result of the final rule according to our analysis. For more information, please refer to the *Economic Impact Analysis for the Secondary Aluminum Supplemental*

Proposal, which is available in the docket.

D. Unfunded Mandates Reform Act (UMRA)

This action does not contain an unfunded mandate of $100 million or more as described in UMRA, 2 U.S.C. 1531–1538, and does not significantly or uniquely affect small governments.

E. Executive Order 13132: Federalism

This action does not have federalism implications. It will not have substantial direct effects on the states, on the relationship between the national government and the states, or on the distribution of power and responsibilities among the various levels of government.

F. Executive Order 13175: Consultation and Coordination With Indian Tribal Governments

This action does not have tribal implications, as specified in Executive Order 13175. There are no secondary aluminum production facilities owned or operated by tribal governments. Thus, Executive Order 13175 does not apply to this action.

G. Executive Order 13045: Protection of Children From Environmental Health Risks and Safety Risks

This action is not subject to Executive Order 13045 because it is not economically significant as defined in Executive Order 12866, and because the EPA does not believe the environmental health or safety risks addressed by this action present a disproportionate risk to children. This action's health and risk assessments are contained in the *Residual Risk Assessment for the Secondary Aluminum Production Source Category in Support of the 2015 Risk and Technology Review Final Rule,* which is available in the docket for this action, and are discussed in section V.G of this preamble.

H. Executive Order 13211: Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution or Use

This action is not subject to Executive Order 13211 because it is not a significant regulatory action under Executive Order 12866.

I. National Technology Transfer and Advancement Act (NTTAA) and 1 CFR Part 51

This final action involves technical standards. The EPA decided to allow the use of ASTM D7520–13, Standard Test Method for Determining the Opacity of a Plume in an Outdoor Ambient Atmosphere, approved December 1, 2013, as an acceptable alternative to EPA Method 9 to meet opacity measurement requirements and is incorporated by reference. The alternative ASTM method determines the opacity of a plume using digital imagery and associated hardware and software. The standard is available from the American Society for Testing and Materials (ASTM), 100 Barr Harbor Drive, Post Office Box C700, West Conshohocken, PA 19428–2959 or at their Web site, *http://www.astm.org.*

Under the original 2000 subpart RRR, the EPA already allows the use of EPA Methods 1, 2, 3, 4, 5, 9, 23, 25A and 26A of 40 CFR part 60, Appendix A. As a result of comments received on the 2012 proposal, EPA Method 26 was identified as a reasonable alternative to EPA Method 26A and EPA Method 204 was identified as a reasonable alternative method for EPA Methods 1 and 2. Method 26A is applicable for determining emissions of hydrogen halides and halogens from stationary sources. This method collects the emission sample isokinetically and is therefore particularly suited for sampling at sources, such as those controlled by wet scrubbers, emitting acid particulate matter. Method 204 is used to determine whether a permanent or temporary enclosure meets the criteria for a total enclosure. In this method, an enclosure is evaluated against a set of criteria, which, if met and all the exhaust gases from the enclosure are ducted to a control device, the capture efficiency is assumed to be 100 percent. The EPA agrees that EPA Methods 26 and 204 are acceptable alternatives for use in this rule. These methods are existing EPA test methods and are not voluntary consensus standards under NTTAA.

EPA–625/3–89–016, Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and -Dibenzofurans (CDDs and CDFs) and 1989 Update, March 1989, U.S. Environmental Protection Agency, is a procedure for assessing the risks associated with exposures to complex mixtures of chlorinated dibenzo-p-dioxins and dibenzofurnas and relates the toxicity of the 210 structurally related chemical pollutants and is based on a limited data base of *in vivo* and *in vitro* toxicity testing. This method is incorporated by reference. The method is available from the National Technical Information Service, 5301 Shawnee Road, Alexandria, VA 22312, or at their Web site, *http://www.ntis.gov.*

For the design and installation of capture and collection systems, the EPA decided to allow the use of American Conference of Governmental Industrial Hygienists (ACGIH) *Industrial Ventilation: A Manual of Recommended Practice for Design,* 27th Edition, 2010 as an alternative to *Industrial Ventilation: A Manual of Recommended Practice,* 23rd Edition, 1998, Chapter 3, ''Local Exhaust Hoods'' and Chapter 5, ''Exhaust System Design Procedure.'' The manuals present information on design, maintenance and evaluation of industrial exhaust ventilation systems. The manuals are available from ACGIH, Customer Service Department, 1330 Kemper Meadow Drive, Cincinnati, Ohio 45240, telephone number (513) 742–2020.

Under 40 CFR 63.7(f) and 40 CFR 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 required testing methods, performance specifications, or procedures in this final rule.

J. Executive Order 12898: Federal Actions To Address Environmental Justice in Minority Populations and Low-Income Populations

The EPA believes the human health or environmental risk addressed by this action will not have potential disproportionately high and adverse human health or environmental effects on minority, low income, or indigenous populations because it does not affect the level of protection provided to human health or the environment. This final rule will not relax the emission limits on regulated sources and will not result in emissions increases. The results of this evaluation are contained in sections III.A, IV.A and V.F and V.G of this preamble.

Because our residual risk assessment determined that there was minimal residual risk associated with the emissions from facilities in this source category, a demographic risk analysis was not necessary for this category. However, the EPA did conduct a proximity analysis for both area and major sources. The results of these analyses are summarized in section IV.A of this preamble and in more detail in the *EJ Screening Report for Area Sources* and the *EJ Screening Report for Major Sources,* which are available in the docket for this rulemaking.

K. Congressional Review Act (CRA)

This action is subject to the CRA, and the EPA will submit a rule report to each House of the Congress and to the Comptroller General of the United

States. This action is not a ''major rule'' as defined by 5 U.S.C. 804(2).

List of Subjects in 40 CFR Part 63

Environmental protection, Administrative practice and procedures, Air pollution control, Hazardous substances, Incorporation by reference, Intergovernmental relations, Reporting and recordkeeping requirements.

Dated: August 14, 2015.

Gina McCarthy,

Administrator.

For the reasons stated in the preamble, the Environmental Protection Agency is amending title 40, chapter I, part 63 of the Code of Federal Regulations (CFR) as follows:

PART 63—NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS FOR SOURCE CATEGORIES

■ 1. The authority citation for part 63 continues to read as follows:

Authority: 42 U.S.C. 7401, et seq.

Subpart A—General Provisions

■ 2. Section 63.14 is amended by:
■ a. Redesignating paragraphs (b) through (r) as (c) through (s);
■ b. Adding new paragraph (b);
■ c. Revising newly redesignated paragraph (h)(87);
■ d. Redesignating newly redesignated paragraphs (m)(3) through (m)(20) as (m)(4) through (m)(21); and
■ e. Adding new paragraph (m)(3).

The additions and revisions read as follows:

§ 63.14 Incorporations by reference.

* * * * *

(b) American Conference of Governmental Industrial Hygienists (ACGIH), Customer Service Department, 1330 Kemper Meadow Drive, Cincinnati, Ohio 45240, telephone number (513) 742–2020.

(1) Industrial Ventilation: A Manual of Recommended Practice, 23rd Edition, 1998, Chapter 3, ''Local Exhaust Hoods'' and Chapter 5, ''Exhaust System Design Procedure.'' IBR approved for §§ 63.1503, 63.1506(c), 63.1512(e), Table 2 to Subpart RRR, Table 3 to Subpart RRR, and Appendix A to Subpart RRR.

(2) Industrial Ventilation: A Manual of Recommended Practice for Design, 27th Edition, 2010. IBR approved for §§ 63.1503, 63.1506(c), 63.1512(e), Table 2 to Subpart RRR, Table 3 to Subpart RRR, and Appendix A to Subpart RRR.

* * * * *

(h) * * *

(87) ASTM D7520–13, Standard Test Method for Determining the Opacity of a Plume in an Outdoor Ambient Atmosphere, approved December 1, 2013. IBR approved for §§ 63.1510(f), 63.1511(d), 63.1512(a), 63.1517(b) and 63.1625(b).

* * * * *

(m) * * *

(3) EPA–625/3–89–016, Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and –Dibenzofurans (CDDs and CDFs) and 1989 Update, March 1989. IBR approved for § 63.1513(d).

* * * * *

Subpart RRR—National Emission Standards for Hazardous Air Pollutants for Secondary Aluminum Production

■ 3. Revise § 63.1501 to read as follows:

§ 63.1501 Dates.

(a) An affected source constructed before February 11, 1999, must comply with the requirements of this subpart by March 24, 2003, except as provided in paragraphs (b) and (c).

(b) The owner or operator of an affected source constructed before February 14, 2012, must comply with the following requirements of this subpart by March 16, 2016: § 63.1505(k) introductory text, (k)(1) through (k)(5), other than the emission standards for HF in (k)(2); § 63.1506 (a)(1), (c)(1), (g)(5), (k)(3), (m)(4), (m)(7), (n)(1); § 63.1510 (b)(5), (b)(9), (d)(2), (d)(3),(f)(1)(ii), (i)(4), (j)(4), (n)(1), (o)(1), (o)(1)(ii), (s)(2)(iv), (t) introductory text, (t)(2)(i), (t)(2)(ii), (t)(4), (t)(5); § 63.1511(a) introductory text, (b) introductory text, (b)(1), (b)(3), (b)(6), (c)(9), (g)(5); § 63.1512(e)(1), (e)(2), (e)(3), (h)(2), (j), (j)(1)(i), (j)(2)(i), (o) introductory text, (o)(1), (o)(3), (p)(2); § 63.1513 (b)(1), (e)(1), (e)(2), (e)(3), (f); § 63.1516 (b) introductory text, (b)(2)(vii), (b)(3)(i); § 63.1517(b)(1)(iii), (b)(4)(ii), (b)(14), (b)(19).

(c) The owner or operator of an affected source constructed before February 14, 2012, must comply with the following requirements of this subpart by September 18, 2017: § 63.1505(i)(4) and (k)(2) emission standards for HF; § 63.1512(e)(4) through (7) requirements for testing existing uncontrolled group 1 furnaces (that is, group 1 furnaces without add-on air pollution control devices); and § 63.1514 requirements for change of furnace classification.

(d) An affected source that commenced construction or reconstruction after February 11, 1999 but before February 14, 2012 must comply with the requirements of this subpart by March 24, 2000 or upon startup, whichever is later, except as provided in paragraphs (b), (c), (e), and (f) of this section.

(e) The owner or operator of an affected source that commences construction or reconstruction after February 14, 2012, must comply with all the requirements of this subpart by September 18, 2015 or upon startup, whichever is later.

(f) The owner or operator of any affected source which is constructed or reconstructed after February 11, 1999, but before February 14, 2012 at any existing aluminum die casting facility, aluminum foundry, or aluminum extrusion facility which otherwise meets the applicability criteria set forth in § 63.1500 must comply with the requirements of this subpart by March 24, 2003 or upon startup, whichever is later, except as provided in paragraphs (b) and (c) of this section. The owner or operator of any affected source which is constructed or reconstructed after February 14, 2012, at any existing aluminum die casting facility, aluminum foundry, or aluminum extrusion facility which otherwise meets the applicability criteria set forth in § 63.1500 must comply with the requirements by September 18, 2015 or upon startup, whichever is later.

§ 63.1502 [Removed and Reserved]

■ 4. Remove and reserve § 63.1502.

■ 5. Section 63.1503 is amended by:
■ a. Adding in alphabetical order a definition of ''ACGIH Guidelines'';
■ b. Revising the definition of ''aluminum scrap shredder'';
■ c. Adding in alphabetical order definitions of ''bale breaker'' and ''capture and collection system'';
■ d. Revising the definitions of ''clean charge,'' ''cover flux,'' ''Group 2 furnace,'' and ''HCl'';
■ e. Adding in alphabetical order a definition of ''HF'';
■ f. Revising the definition of ''residence time'';
■ g. Adding in alphabetical order a definition of ''round top furnace'';
■ h. Revising the definitions of ''scrap dryer/delacquering kiln/decoating kiln'' and ''secondary aluminum processing unit (SAPU)''; and
■ i. Adding in alphabetical order definitions of ''shutdown,'' ''startup,'' ''tap,'' and ''total reactive fluorine flux injection rate''.

The additions and revisions read as follows:

§ 63.1503 Definitions.

* * * * *

ACGIH Guidelines means chapters 3 and 5 of *Industrial Ventilation: A Manual of Recommended Practice* 23rd edition or appropriate chapters of *Industrial Ventilation: A Manual of Recommended Practice for Design* 27th edition (incorporated by reference, see § 63.14).

* * * * *

Aluminum scrap shredder means a high speed or low speed unit that crushes, grinds, granulates, shears or breaks aluminum scrap into a more uniform size prior to processing or charging to a *scrap dryer/delacquering kiln/decoating kiln,* or furnace. A *bale breaker* is not an *aluminum scrap shredder.* Shearing and cutting operations performed at rolling mills and aluminum finishing operations (such as slitters) are not aluminum scrap shredders.

* * * * *

Bale breaker means a device used to break apart a bale of aluminum scrap for further processing. Bale breakers are not used to crush, grind, granulate, shear or break aluminum scrap into more uniform size pieces.

* * * * *

Capture and collection system means the system, including duct systems and fans, and, in some cases, hoods, used to collect a contaminant at or near its source, and for affected sources equipped with an air pollution control device, transport the contaminated air to the air cleaning device.

* * * * *

Clean charge means furnace charge materials, including molten aluminum; T-bar; sow; ingot; billet; pig; alloying elements; aluminum scrap known by the owner or operator to be entirely free of paints, coatings, and lubricants; uncoated/unpainted aluminum chips that have been thermally dried or treated by a centrifugal cleaner; aluminum scrap dried at 343 °C (650 °F) or higher; aluminum scrap delacquered/decoated at 482 °C (900 °F) or higher; and runaround scrap. Anodized aluminum that contains dyes or sealants containing organic compounds is not clean charge.

Cover flux means salt added to the surface of molten aluminum in a *group 1* or *group 2 furnace,* without surface agitation of the molten aluminum, for the purpose of preventing oxidation. Any flux added to a rotary furnace is not a cover flux.

* * * * *

Group 2 furnace means a furnace of any design that melts, holds, or processes only *clean charge* and that performs no *fluxing* or performs *fluxing* using only nonreactive, non-HAP-containing/non-HAP-generating gases or agents. Unheated pots, to which no flux is added and that are used to transport metal, are not furnaces.

HCl means hydrogen chloride.

HF means hydrogen fluoride.

* * * * *

Residence time means, for an *afterburner,* the duration of time required for gases to pass through the *afterburner* combustion zone. *Residence time* is calculated by dividing the *afterburner* combustion zone volume in cubic feet by the volumetric flow rate of the gas stream in actual cubic feet per second. The combustion zone volume includes the reaction chamber of the afterburner in which the waste gas stream is exposed to the direct combustion flame and the complete refractory lined portion of the furnace stack up to the measurement thermocouple.

* * * * *

Round top furnace means a cylindrically-shaped reverberatory furnace that has a top that is removed for charging and other furnace operations.

* * * * *

Scrap dryer/delacquering kiln/decoating kiln means a unit used primarily to remove various organic contaminants such as oil, paint, lacquer, ink, plastic, and/or rubber from *aluminum scrap* (including used beverage containers) prior to melting, or that separates aluminum foil from paper and plastic in scrap.

Secondary aluminum processing unit (SAPU). An existing SAPU means all existing group 1 furnaces and all existing in-line fluxers within a secondary aluminum production facility. Each existing group 1 furnace or existing in-line fluxer is considered an emission unit within a secondary aluminum processing unit. A new SAPU means any combination of individual group 1 furnaces and in-line fluxers within a secondary aluminum processing facility which either were constructed or reconstructed after February 11, 1999, or have been permanently redesignated as new emission units pursuant to § 63.1505(k)(6). Each of the group 1 furnaces or in-line fluxers within a new SAPU is considered an emission unit within that secondary aluminum processing unit. A secondary aluminum production facility may have more than one new SAPU.

* * * * *

Shutdown means the period of operation for thermal chip dryers, scrap dryers/delacquering kilns, decoating kilns, dross-only furnaces, group 1 furnaces, in-line fluxers, sweat furnaces and group 2 furnaces that begins when the introduction of feed/charge is intentionally halted, the source of heat to the emissions unit is turned off, and product has been removed from the emission unit to the greatest extent practicable (*e.g.*, by tapping a furnace). Shutdown ends when the emission unit is near ambient temperature.

* * * * *

Startup means the period of operation for thermal chip dryers, scrap dryers/delacquering kilns, decoating kilns, dross-only furnaces, group 1 furnaces, in-line fluxers, sweat furnaces and group 2 furnaces that begins with equipment warming from a shutdown, that is, the equipment is at or near ambient temperature. Startup ends at the point that flux or feed/charge is introduced.

* * * * *

Tap means the end of an operating cycle of any individual furnace when processed molten aluminum is poured from that furnace.

* * * * *

Total reactive fluorine flux injection rate means the sum of the total weight of fluorine in the gaseous or liquid reactive flux added to an uncontrolled group 1 furnace, and the total weight of fluorine in the solid reactive flux added to an uncontrolled group 1 furnace, divided by the total weight of feed/charge, as determined by the procedure in § 63.1512(o).

■ 6. Section 63.1505 is amended by revising paragraphs (a), (i)(4), (k) introductory text, (k)(1) through (3), and (k)(6) to read as follows:

§ 63.1505 Emission standards for affected sources and emission units.

(a) *Summary.* The owner or operator of a new or existing affected source must comply at all times with each applicable limit in this section, including periods of startup and shutdown. Table 1 to this subpart summarizes the emission standards for each type of source.

* * * * *

(i) * * *

(4) 0.20 kg of HF per Mg (0.40 lb of HF per ton) of feed/charge from an uncontrolled group 1 furnace and 0.20 kg of HCl per Mg (0.40 lb of HCl per ton) of feed/charge or, if the furnace is equipped with an add-on air pollution control device, 10 percent of the uncontrolled HCl emissions, by weight, for a group 1 furnace at a secondary aluminum production facility that is a major source.

* * * * *

(k) *Secondary aluminum processing unit.* The owner or operator must comply with the emission limits calculated using the equations for PM, HCl and HF in paragraphs (k)(1) and (2) of this section for each secondary aluminum processing unit at a secondary aluminum production facility that is a major source. The owner or operator must comply with the emission limit calculated using the equation for D/F in paragraph (k)(3) of this section for each secondary aluminum processing unit at a secondary aluminum production facility that is a major or area source.

(1) The owner or operator must not discharge or allow to be discharged to the atmosphere any 3-day, 24-hour rolling average emissions of PM in excess of:

$$L_{c_{PM}} = \frac{\sum_{i=1}^{n}\left(L_{ti_{PM}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \qquad \text{(Eq. 1)}$$

Where:

L_{tiPM} = The PM emission limit for individual emission unit i in paragraph (i)(1) and (2) of this section for a group 1 furnace or in paragraph (j)(2) of this section for an in-line fluxer;

T_{ti} = The mass of feed/charge for 24 hours for individual emission unit i; and

L_{cPM} = The daily PM emission limit for the secondary aluminum processing unit which is used to calculate the 3-day, 24-hour PM emission limit applicable to the SAPU.

Note: In-line fluxers using no reactive flux materials cannot be included in this calculation since they are not subject to the PM limit.

(2) The owner or operator must not discharge or allow to be discharged to the atmosphere any 3-day, 24-hour rolling average emissions of HCl or HF in excess of:

$$L_{c_{HCl/HF}} = \frac{\sum_{i=1}^{n}\left(L_{ti_{HCl/HF}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \qquad \text{(Eq. 2)}$$

Where:

$L_{tiHCl/HF}$ = The HCl emission limit for individual emission unit i in paragraph (i)(4) of this section for a group 1 furnace or in paragraph (j)(1) of this section for an in-line fluxer; or the HF emission limit for individual emission unit i in paragraph (i)(4) of this section for an uncontrolled group 1 furnace; and

$L_{cHCl/HF}$ = The daily HCl or HF emission limit for the secondary aluminum processing unit which is used to calculate the 3-day, 24-hour HCl or HF emission limit applicable to the SAPU.

Note: Only uncontrolled group 1 furnaces are included in this HF limit calculation. In-line fluxers using no reactive flux materials cannot be included in this calculation since they are not subject to the HCl or HF limit.

(3) The owner or operator must not discharge or allow to be discharged to the atmosphere any 3-day, 24-hour rolling average emissions of D/F in excess of:

$$L_{c_{D/F}} = \frac{\sum_{i=1}^{n}\left(L_{ti_{D/F}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \qquad \text{(Eq. 3)}$$

Where:

$L_{tiD/F}$ = The D/F emission limit for individual emission unit i in paragraph (i)(3) of this section for a group 1 furnace; and

$L_{cD/F}$ = The daily D/F emission limit for the secondary aluminum processing unit which is used to calculate the 3-day, 24-hour D/F emission limit applicable to the SAPU.

Note: Clean charge furnaces cannot be included in this calculation since they are not subject to the D/F limit.

* * * * *

(6) With the prior approval of the permitting authority for major sources, or the Administrator for area sources, an owner or operator may redesignate any existing group 1 furnace or in-line fluxer at a secondary aluminum production facility as a new emission unit. Any emission unit so redesignated may thereafter be included in a new SAPU at that facility. Any such redesignation will be solely for the purpose of this NESHAP and will be irreversible.

■ 7. Section 63.1506 is amended by:
■ a. Revising paragraph (a)(1);
■ b. Adding paragraph (a)(5);
■ c. Revising paragraph (c)(1);
■ d. Adding paragraph (c)(4);
■ e. Revising paragraphs (g)(5), (k)(3), and (m)(4);
■ f. Adding paragraph (m)(7); and
■ g. Revising paragraph (n)(1).

The additions and revisions read as follows:

§ 63.1506 Operating requirements.

(a) *Summary.* (1) The owner or operator must operate all new and existing affected sources and control equipment according to the requirements in this section. The affected sources, and their associated control equipment, listed in § 63.1500(c)(1) through (4) of this subpart that are located at a secondary aluminum production facility that is an area source are subject to the operating requirements of paragraphs (b), (c), (d), (f), (g), (h), (m), (n), and (p) of this section.

* * * * *

(5) At all times, the owner or operator 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 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) Design and install a system for the capture and collection of emissions to meet the engineering standards for minimum exhaust rates or facial inlet velocities as contained in the ACGIH Guidelines (incorporated by reference, see § 63.14);

* * * * *

(4) In lieu of paragraph (c)(1) of this section, the owner or operator of a sweat furnace may design, install and operate each sweat furnace in accordance with paragraphs (c)(4)(i) through (iii) of this section.

(i) As demonstrated by an annual negative air flow test conducted in accordance with § 63.1510(d)(3), air flow must be into the sweat furnace or towards the plane of the sweat furnace opening.

(ii) The owner or operator must maintain and operate the sweat furnace in a manner consistent with the good practices requirements for minimizing emissions, including unmeasured emissions, in paragraph (a)(5) of this section. Procedures that will minimize unmeasured emissions may include, but are not limited to the following:

(A) Increasing the exhaust rate from the furnace with draft fans, so as to capture emissions that might otherwise escape from the sweat furnace opening;

(B) Minimizing the time the sweat furnace doors are open;

(C) Keeping building doors and other openings closed to the greatest extent possible to minimize drafts that would divert emissions from being drawn into the sweat furnace;

(D) Maintaining burners on low-fire or pilot operation while the doors are open;

(E) Conducting periodic inspections and maintenance of sweat furnace components to ensure their proper operation and performance including but not limited to, door assemblies, seals, combustion chamber refractory material, afterburner and stack refractory, blowers, fans, dampers, burner tubes, door raise cables, pilot light assemblies, baffles, sweat furnace and afterburner shells and other internal structures.

(iii) The owner or operator must document in their operation, maintenance, and monitoring (OM&M) plan the procedures to be used to minimize emissions, including unmeasured emissions, in addition to the procedures to ensure the proper operation and maintenance of the sweat furnace.

* * * * *

(g) * * *

(5) For a continuous injection device, maintain free-flowing lime in the hopper to the feed device at all times and maintain the lime feeder setting at or above the level established during the performance test.

* * * * *

(k) * * *

(3) For a continuous injection system, maintain free-flowing lime in the hopper to the feed device at all times and maintain the lime feeder setting at or above the level established during the performance test.

* * * * *

(m) * * *

(4) For a continuous lime injection system, maintain free-flowing lime in the hopper to the feed device at all times and maintain the lime feeder setting at or above the level established during the performance test.

* * * * *

(7) The operation of capture/collection systems and control devices associated with natural gas-fired, propane-fired or electrically heated group 1 furnaces that will be idled for at least 24 hours after the furnace cycle has been completed may be temporarily stopped. Operation of these capture/collection systems and control devices must be restarted before feed/charge, flux or alloying materials are added to the furnace.

(n) * * *

(1) Maintain the total reactive chlorine flux injection rate and fluorine flux injection rate for each operating cycle or time period used in the performance test, at or below the average rate established during the performance test.

* * * * *

■ 8. Section 63.1510 is amended by:

■ a. Revising paragraphs (a), (b) introductory text, and (b)(5);

■ b. Adding paragraph (b)(9);

■ c. Revising paragraph (d)(2) introductory text;

■ d. Adding paragraphs (d)(2)(i) through (iv) and (d)(3);

■ e. Revising paragraphs (e) and (f)(1)(ii);

■ f. Adding paragraph (f)(4);

■ g. Revising paragraph (i)(3);

■ h. Adding paragraph (i)(4);

■ i. Revising paragraphs (j)(1)(ii), (j)(4), (n)(1) and (2), (o)(1), (s)(2)(iv), (s)(3), and (t) introductory text;

■ j. Adding paragraphs (t)(2)(i) through (iii); and

■ k. Revising paragraphs (t)(4) and (5).

The additions and revisions read as follows:

§ 63.1510 Monitoring requirements.

(a) *Summary.* The owner or operator of a new or existing affected source or emission unit must monitor all control equipment and processes according to the requirements in this section. Monitoring requirements for each type of affected source and emission unit are summarized in Table 3 to this subpart. Area sources are subject to monitoring requirements for those affected sources listed in § 63.1500(c)(1) through (4) of this subpart, and associated control equipment as required by paragraphs (b) through (k), (n) through (q), and (s) through (w) of this section, including but not limited to:

(1) The OM&M plan required in paragraph (b) of this section pertaining to each affected source listed in § 63.1500(c)(1) through (4) of this subpart,

(2) The labeling requirements described in paragraph (c) of this section pertaining to group 1 furnaces processing other than clean charge, and scrap dryer/delacquering kiln/decoating kilns,

(3) The requirements for capture and collection described in paragraph (d) of this section for each controlled affected source (*i.e.*, affected sources with an add-on air pollution control device), listed in § 63.1500(c)(1) through (4) of this subpart,

(4) The feed/charge weight monitoring requirements described in paragraph (e) of this section applicable to group 1 furnaces processing other than clean charge, scrap dryer/delacquering kiln/decoating kilns and thermal chip dryers,

(5) The bag leak detection system requirements described in paragraph (f) of this section applicable to all bag leak detection systems installed on fabric filters and lime injected fabric filters used to control each affected source listed in § 63.1500(c)(1)–(4) of this subpart,

(6) The requirements for afterburners described in paragraph (g) of this

section applicable to sweat furnaces, thermal chip dryers, and scrap dryer/delacquering kiln/decoating kilns,

(7) The requirements for monitoring fabric filter inlet temperature described in paragraph (h) of this section for all lime injected fabric filters used to control group 1 furnaces processing other than clean charge, sweat furnaces and scrap dryer/delacquering kiln/decoating kilns,

(8) The requirements for monitoring lime injection described in paragraph (i) of this section applicable to all lime injected fabric filters used to control emissions from group 1 furnaces processing other than clean charge, thermal chip dryers, sweat furnaces and scrap dryer/delacquering kiln/decoating kilns,

(9) The requirements for monitoring total reactive flux injection described in paragraph (j) of this section for all group 1 furnaces processing other than clean charge,

(10) The requirements described in paragraph (k) of this section for thermal chip dryers,

(11) The requirements described in paragraph (n) of this section for controlled group 1 sidewell furnaces processing other than clean charge,

(12) The requirements described in paragraph (o) of this section for uncontrolled group 1 sidewell furnaces processing other than clean charge,

(13) The requirements described in paragraph (p) of this section for scrap inspection programs for uncontrolled group 1 furnaces,

(14) The requirements described in paragraph (q) of this section for monitoring scrap contamination level for uncontrolled group 1 furnaces,

(15) The requirements described in paragraph (s) of this section for secondary aluminum processing units, limited to compliance with limits for emissions of D/F from group 1 furnaces processing other than clean charge,

(16) The requirements described in paragraph (t) of this section for secondary aluminum processing units limited to compliance with limits for emissions of D/F from group 1 furnaces processing other than clean charge,

(17) The requirements described in paragraph (u) of this section for secondary aluminum processing units limited to compliance with limits for emissions of D/F from group 1 furnaces processing other than clean charge,

(18) The requirements described in paragraph (v) of this section for alternative lime addition monitoring methods applicable to lime-injected fabric filters used to control emissions from group 1 furnaces processing other than clean charge, thermal chip dryers, sweat furnaces and scrap dryer/delacquering kiln/decoating kilns, and

(19) The requirements described in paragraph (w) of this section for approval of alternate methods for monitoring group 1 furnaces processing other than clean charge, thermal chip dryers, scrap dryer/delacquering kiln/decoating kilns and sweat furnaces and associated control devices for the control of D/F emissions.

(b) *Operation, maintenance, and monitoring (OM&M) plan.* The owner or operator must prepare and implement for each new or existing affected source and emission unit, a written OM&M plan. The owner or operator of an existing affected source must submit the OM&M plan to the permitting authority for major sources, or the Administrator for area sources no later than the compliance date established by § 63.1501(a). The owner or operator of any new affected source must submit the OM&M plan to the permitting authority for major sources, or the Administrator for area sources within 90 days after a successful initial performance test under § 63.1511(b), or within 90 days after the compliance date established by § 63.1501(b) if no initial performance test is required. The plan must be accompanied by a written certification by the owner or operator that the OM&M plan satisfies all requirements of this section and is otherwise consistent with the requirements of this subpart. The owner or operator must comply with all of the provisions of the OM&M plan as submitted to the permitting authority for major sources, or the Administrator for area sources, unless and until the plan is revised in accordance with the following procedures. If the permitting authority for major sources, or the Administrator for area sources determines at any time after receipt of the OM&M plan that any revisions of the plan are necessary to satisfy the requirements of this section or this subpart, the owner or operator must promptly make all necessary revisions and resubmit the revised plan. If the owner or operator determines that any other revisions of the OM&M plan are necessary, such revisions will not become effective until the owner or operator submits a description of the changes and a revised plan incorporating them to the permitting authority for major sources, or the Administrator for area sources. Each plan must contain the following information:

* * * * *

(5) Procedures for monitoring process and control device parameters, including lime injection rates, procedures for annual inspections of afterburners, and if applicable, the procedure to be used for determining charge/feed (or throughput) weight if a measurement device is not used.

* * * * *

(9) Procedures to be followed when changing furnace classifications under the provisions of § 63.1514.

* * * * *

(d) * * *

(2) Inspect each capture/collection and closed vent system at least once each calendar year to ensure that each system is operating in accordance with the operating requirements in § 63.1506(c) and record the results of each inspection. This inspection shall include a volumetric flow rate measurement taken at a location in the ductwork downstream of the hoods that is representative of the actual volumetric flow rate without interference due to leaks, ambient air added for cooling or ducts from other hoods. The flow rate measurement must be performed in accordance with paragraphs (d)(2)(i), (ii), or (iii) of this section. As an alternative to the flow rate measurement specified in this paragraph, the inspection may satisfy the requirements of this paragraph, including the operating requirements in § 63.1506(c), by including permanent total enclosure verification in accordance with paragraph (d)(2)(i) or (iv) of this section. Inspections that fail to successfully demonstrate that the requirements of § 63.1506(c) are met, must be followed by repair or adjustment to the system operating conditions and a follow up inspection within 45 days to demonstrate that § 63.1506(c) requirements are fully met.

(i) Conduct annual flow rate measurements using EPA Methods 1 and 2 in Appendix A to 40 CFR part 60, or conduct annual verification of a permanent total enclosure using EPA Method 204; or you may follow one of the three alternate procedures described in paragraphs (ii), (iii), or (iv) of this section to maintain system operations in accordance with an operating limit established during the performance test. The operating limit is determined as the average reading of a parametric monitoring instrument (Magnehelic®, manometer, anemometer, or other parametric monitoring instrument) and technique as described in paragraphs (d)(2)(ii), (iii), and (iv) of this section. A deviation, as defined in paragraphs (ii), (iii), and (iv) of this section, from the parametric monitoring operating limit requires the owner or operator to make repairs or adjustments to restore normal operation within 45 days.

(ii) As an alternative to annual flow rate measurements using EPA Methods 1 and 2, measurement with EPA Methods 1 and 2 can be performed once every 5 years, provided that:

(A) A flow rate indicator consisting of a pitot tube and differential pressure gauge (Magnehelic®, manometer or other differential pressure gauge) is installed with the pitot tube tip located at a representative point of the duct proximate to the location of the Methods 1 and 2 measurement site; and

(B) The flow rate indicator is installed and operated in accordance with the manufacturer's specifications; and

(C) The differential pressure is recorded during the Method 2 performance test series; and

(D) Daily differential pressure readings are made by taking three measurements with at least 5 minutes between each measurement and averaging the three measurements; and readings are recorded daily and maintained at or above 90 percent of the average pressure differential indicated by the flow rate indicator during the most recent Method 2 performance test series; and

(E) An inspection of the pitot tube and associated lines for damage, plugging, leakage and operational integrity is conducted at least once per year; or

(iii) As an alternative to annual flow rate measurements using EPA Methods 1 and 2, measurement with EPA Methods 1 and 2 can be performed once every 5 years, provided that:

(A) Daily measurements of the capture and collection system's fan revolutions per minute (RPM) or fan motor amperage (amps) are made by taking three measurements with at least 5 minutes between each measurement, and averaging the three measurements; and readings are recorded daily and maintained at or above 90 percent of the average RPM or amps measured during the most recent Method 2 performance test series; or

(B) A static pressure measurement device is installed in the duct immediately downstream of the hood exit, and daily pressure readings are made by taking three measurements with at least 5 minutes between each measurement, and averaging the three measurements; and readings are recorded daily and maintained at 90 percent or better of the average vacuum recorded during the most recent Method 2 performance test series; or

(C) A hotwire anemometer, ultrasonic flow meter, cross-duct pressure differential sensor, venturi pressure differential monitoring or orifice plate equipped with an associated thermocouple and automated data logging software and associated hardware is installed; and daily readings are made by taking three measurements with at least 5 minutes between each measurement, and averaging the three measurements; and readings are recorded daily and maintained at 90 percent or greater of the average readings during the most recent Method 2 performance test series; or

(D) For booth-type hoods, hotwire anemometer measurements of hood face velocity are performed simultaneously with EPA Method 1 and 2 measurements, and the annual hood face velocity measurements confirm that the enclosure draft is maintained at 90 percent or greater of the average readings during the most recent Method 2 performance test series. Daily readings are made by taking three measurements with at least 5 minutes between each measurement, and averaging the three measurements; and readings are recorded daily and maintained at 90 percent or greater of the average readings during the most recent Method 1 and 2 performance test series.

(iv) As an alternative to the annual verification of a permanent total enclosure using EPA Method 204, verification can be performed once every 5 years, provided that:

(A) Negative pressure in the enclosure is directly monitored by a pressure indicator installed at a representative location;

(B) Pressure readings are recorded daily or the system is interlocked to halt material feed should the system not operate under negative pressure;

(C) An inspection of the pressure indicator for damage and operational integrity is conducted at least once per calendar year.

(3) For sweat furnaces, in lieu of paragraph (d)(2) of this section, the owner or operator of a sweat furnace may inspect each sweat furnace at least once each calendar year to ensure that they are being operated in accordance with the negative air flow requirements in § 63.1506(c)(4). The owner or operator of a sweat furnace must demonstrate negative air flow into the sweat furnace in accordance with paragraphs (d)(3)(i) through (iii) of this section.

(i) Perform an annual visual smoke test to demonstrate airflow into the sweat furnace or towards the plane of the sweat furnace opening;

(ii) Perform the smoke test using a smoke source, such as a smoke tube, smoke stick, smoke cartridge, smoke candle or other smoke source that produces a persistent and neutral buoyancy aerosol; and

(iii) Perform the visual smoke test at a safe distance from and near the center of the sweat furnace opening.

(e) *Feed/charge weight.* The owner or operator of an affected source or emission unit subject to an emission limit in kg/Mg (lb/ton) or µg/Mg (gr/ton) of feed/charge must install, calibrate, operate, and maintain a device to measure and record the total weight of feed/charge to, or the aluminum production from, the affected source or emission unit over the same operating cycle or time period used in the performance test. Feed/charge or aluminum production within SAPUs must be measured and recorded on an emission unit-by-emission unit basis. As an alternative to a measurement device, the owner or operator may use a procedure acceptable to the permitting authority for major sources, or the Administrator for area sources to determine the total weight of feed/charge or aluminum production to the affected source or emission unit.

* * * * *

(f) * * *

(1) * * *

(ii) Each bag leak detection system must be installed, calibrated, operated, and maintained according to the manufacturer's operating instructions.

* * * * *

(4) As an alternative to the requirements of paragraph (f)(3) of this section, the owner or operator of a new or existing aluminum scrap shredder may measure the opacity of the emissions discharged through a stack or stacks using ASTM Method D7520–13 (incorporated by reference, see § 63.14) subject to the requirements of paragraphs § 63.1510(f)(4)(i) through (iv) of this section. Each test must consist of five 6-minute observations in a 30-minute period.

(i) During the digital camera opacity technique (DCOT) certification procedure outlined in Section 9.2 of ASTM D7520–13, the owner or operator or the DCOT vendor must present the plumes in front of various backgrounds of color and contrast representing conditions anticipated during field use such as blue sky, trees, and mixed backgrounds (clouds and/or a sparse tree stand).

(ii) The owner or operator must also have standard operating procedures in place including daily or other frequency quality checks to ensure that equipment is within manufacturing specifications as outlined in Section 8.1 of ASTM D7520–13.

(iii) The owner or operator must follow the recordkeeping procedures outlined in § 63.10(b)(1) for DCOT certification, compliance report, data sheets and all raw unaltered JPEGs used for opacity and certification determination.

(iv) The owner or operator or the DCOT vendor must have a minimum of four (4) independent technology users apply the software to determine the visible opacity of the 300 certification plumes. For each set of 25 plumes, the user may not exceed 15 percent opacity on any one reading and the average error must not exceed 7.5 percent opacity.

* * * * *

(i) * * *

(3) An owner or operator who intermittently adds lime to a lime-injected fabric filter must obtain approval from the permitting authority for major sources, or the Administrator for area sources for a lime addition monitoring procedure. The permitting authority for major sources, or the Administrator for area sources will not approve a monitoring procedure unless data and information are submitted establishing that the procedure is adequate to ensure that relevant emission standards will be met on a continuous basis.

(4) At least once per month, verify that the lime injection rate in pounds per hour (lb/hr) is no less than 90 percent of the lime injection rate used to demonstrate compliance during your most recent performance test. If the monthly check of the lime injection rate is below the 90 percent, the owner or operator must repair or adjust the lime injection system to restore normal operation within 45 days. The owner or operator may request from the permitting authority for major sources, or the Administrator for area sources, an extension of up to an additional 45 days to demonstrate that the lime injection rate is no less than 90 percent of the lime injection rate used to demonstrate compliance during the most recent performance test. In the event that a lime feeder is repaired or replaced, the feeder must be calibrated, and the feed rate must be restored to the lb/hr feed rate operating limit established during the most recent performance test within 45 days. The owner or operator may request from the permitting authority for major sources, or the Administrator for area sources, an extension of up to an additional 45 days to complete the repair or replacement and establishing a new setting. The repair or replacement, and the establishment of the new feeder setting(s) must be documented in accordance with the recordkeeping requirements of § 63.1517.

(j) * * *

(1) * * *

(ii) The accuracy of the weight measurement device must be ±1 percent of the weight of the reactive component of the flux being measured. The owner or operator may apply to the permitting authority for major sources, or the Administrator for area sources for permission to use a weight measurement device of alternative accuracy in cases where the reactive flux flow rates are so low as to make the use of a weight measurement device of ±1 percent impracticable. A device of alternative accuracy will not be approved unless the owner or operator provides assurance through data and information that the affected source will meet the relevant emission standards.

* * * * *

(4) Calculate and record the total reactive flux injection rate for each operating cycle or time period used in the performance test using the procedure in § 63.1512(o). For solid flux that is added intermittently, record the amount added for each operating cycle or time period used in the performance test using the procedures in § 63.1512(o).

* * * * *

(n) * * *

(1) Record in an operating log for each tap of a sidewell furnace whether the level of molten metal was above the top of the passage between the sidewell and hearth during reactive flux injection, unless the furnace hearth was also equipped with an add-on control device. If visual inspection of the molten metal level is not possible, the molten metal level must be determined using physical measurement methods.

(2) Submit a certification of compliance with the operational standards in § 63.1506(m)(6) for each 6-month reporting period. Each certification must contain the information in § 63.1516(b)(2)(iii).

(o) * * *

(1) The owner or operator must develop, in consultation with the permitting authority for major sources, or the Administrator for area sources, a written site-specific monitoring plan. The site-specific monitoring plan must be submitted to the permitting authority for major sources, or the Administrator for area sources as part of the OM&M plan. The site-specific monitoring plan must contain sufficient procedures to ensure continuing compliance with all applicable emission limits and must demonstrate, based on documented test results, the relationship between emissions of PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces), and the proposed monitoring parameters for each pollutant. Test data must establish the highest level of PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces) that will be emitted from the furnace in accordance with § 63.1511(b)(1). If the permitting authority for major sources, or the Administrator for area sources determines that any revisions of the site-specific monitoring plan are necessary to meet the requirements of this section or this subpart, the owner or operator must promptly make all necessary revisions and resubmit the revised plan.

(i) The owner or operator of an existing affected source must submit the site-specific monitoring plan to the permitting authority for major sources, or the Administrator for area sources for review at least 6 months prior to the compliance date.

(ii) The permitting authority for major sources, or the Administrator for area sources will review and approve or disapprove a proposed plan, or request changes to a plan, based on whether the plan contains sufficient provisions to ensure continuing compliance with applicable emission limits and demonstrates, based on documented test results, the relationship between emissions of PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces) and the proposed monitoring parameters for each pollutant. Test data must establish the highest level of PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces) that will be emitted from the furnace. Subject to approval of the OM&M plan, the highest levels may be determined by conducting performance tests and monitoring operating parameters in accordance with § 63.1511(b)(1).

* * * * *

(s) * * *

(2) * * *

(iv) The inclusion of any periods of startup or shutdown in emission calculations.

(3) To revise the SAPU compliance provisions within the OM&M plan prior to the end of the permit term, the owner or operator must submit a request to the permitting authority for major sources, or the Administrator for area sources containing the information required by paragraph (s)(1) of this section and obtain approval of the permitting authority for major sources, or the Administrator for area sources prior to implementing any revisions.

(t) *Secondary aluminum processing unit*. Except as provided in paragraph (u) of this section, the owner or operator must calculate and record the 3-day, 24-hour rolling average emissions of PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces) for each secondary aluminum processing unit on a daily basis. To calculate the 3-day, 24-hour rolling average, the owner or operator must:

* * * * *

(2) * * *

(i) Where no performance test has been conducted, for a particular emission unit, because the owner of operator has, with the approval of the permitting authority for major sources, or the Administrator for area sources, chosen to determine the emission rate of an emission unit by testing a representative unit, in accordance with § 63.1511(f), the owner or operator shall use the emission rate determined from the representative unit in the SAPU emission rate calculation required in § 63.1510(t)(4).

(ii) Except as provided in paragraph (t)(2)(iii) of this section, if the owner or operator has not conducted performance tests for HCl (and HF for an uncontrolled group 1 furnace) or for HCl for an in-line fluxer, in accordance with the provisions of § 63.1512(d)(3), (e)(3), or (h)(2), the calculation required in § 63.1510(t)(4) to determine SAPU-wide HCl and HF emissions shall be made under the assumption that all chlorine contained in reactive flux added to the emission unit is emitted as HCl and all fluorine contained in reactive flux added to the emission unit is emitted as HF.

(iii) Prior to the date by which the initial performance test for HF emissions from uncontrolled group 1 furnaces is conducted, or is required to be conducted, the calculation required in § 63.1505(k) to determine the SAPU-wide HF emission limit and the calculation required in § 63.1510(t)(4) to determine the SAPU-wide HF emission rate must exclude HF emissions from untested uncontrolled group 1 furnaces and feed/charge processed in untested uncontrolled group 1 furnaces.

* * * * *

(4) Compute the 24-hour daily emission rate using Equation 4:

$$E_{day} = \frac{\sum_{i=1}^{n}\left(T_i \times ER_i\right)}{\sum_{i=1}^{n} T_i} \qquad \text{(Eq. 4)}$$

Where:

E_{day} = The daily PM, HCl, and D/F (and HF for uncontrolled group 1 furnaces) emission rate for the secondary aluminum processing unit for the 24-hour period;
T_i = The total amount of feed, or aluminum produced, for emission unit i for the 24-hour period (tons or Mg);
ER_i = The measured emission rate for emission unit i as determined in the performance test (lb/ton or µg/Mg of feed/charge); and
n = The number of emission units in the secondary aluminum processing unit.

(5) Calculate and record the 3-day, 24-hour rolling average for each pollutant each day by summing the daily emission rates for each pollutant over the 3 most recent consecutive days and dividing by 3. The SAPU is in compliance with an applicable emission limit if the 3-day, 24-hour rolling average for each pollutant is no greater than the applicable SAPU emission limit determined in accordance with § 63.1505(k)(1)–(3).

* * * * *

■ 9. Section 63.1511 is amended by:
■ a. Revising paragraphs (a), (b) introductory text, and (b)(1) and (3);
■ b. Adding paragraphs (b)(6) and (7);
■ c. Revising paragraphs (c)(9), (d), and (f) introductory text;
■ d. Adding paragraph (f)(6);
■ e. Revising paragraph (g) introductory text;
■ f. Adding paragraph (g)(5); and
■ g. Revising paragraph (i) introductory text.

The additions and revisions read as follows:

§ 63.1511 Performance test/compliance demonstration general requirements.

(a) *Site-specific test plan.* Prior to conducting any performance test required by this subpart, the owner or operator must prepare a site-specific test plan which satisfies all of the rule requirements, and must obtain approval of the plan pursuant to the procedures set forth in § 63.7. Performance tests shall be conducted under such conditions as the Administrator specifies to the owner or operator based on representative performance of the affected source for the period being tested. Upon request, the owner or operator shall make available to the Administrator such records as may be necessary to determine the conditions of performance tests.

(b) *Initial performance test.* Following approval of the site-specific test plan, the owner or operator must demonstrate initial compliance with each applicable emission, equipment, work practice, or operational standard for each affected source and emission unit, and report the results in the notification of compliance status report as described in § 63.1515(b). The owner or operator of any affected source constructed before February 14, 2012, for which an initial performance test is required to demonstrate compliance must conduct this initial performance test no later than the date for compliance established by § 63.1501(a), (b), or (c). The owner or operator of any affected source constructed after February 14, 2012, for which an initial performance test is required must conduct this initial performance test within 180 days after the date for compliance established by § 63.1501(e) or (f). Except for the date by which the performance test must be conducted, the owner or operator must conduct each performance test in accordance with the requirements and procedures set forth in § 63.7(c). Owners or operators of affected sources located at facilities which are area sources are subject only to those performance testing requirements pertaining to D/F. Owners or operators of sweat furnaces meeting the specifications of § 63.1505(f)(1) are not required to conduct a performance test.

(1) The performance tests must be conducted under representative conditions expected to produce the highest level of HAP emissions expressed in the units of the emission standards for the HAP (considering the extent of feed/charge contamination, reactive flux addition rate and feed/charge rate). If a single test condition is not expected to produce the highest level of emissions for all HAP, testing under two or more sets of conditions (for example high contamination at low feed/charge rate, and low contamination at high feed/charge rate) may be required. Any subsequent performance tests for the purposes of establishing new or revised parametric limits shall be allowed upon pre-approval from the permitting authority for major sources, or the Administrator for area sources. These new parametric settings shall be

used to demonstrate compliance for the period being tested.

* * * * *

(3) Each performance test for a batch process must consist of three separate runs; pollutant sampling for each run must be conducted over the entire process operating cycle. Additionally, for batch processes where the length of the process operating cycle is not known in advance, and where isokinetic sampling must be conducted based on the procedures in Method 5 in appendix A to part 60, use the following procedure to ensure that sampling is conducted over the entire process operating cycle:

(i) Choose a minimum operating cycle length and begin sampling assuming this minimum length will be the run time (*e.g.*, if the process operating cycle is known to last from four to six hours, then assume a sampling time of four hours and divide the sampling time evenly between the required number of traverse points);

(ii) After each traverse point has been sampled once, begin sampling each point again for the same time per point, in the reverse order, until the operating cycle is complete. All traverse points as required by Method 1 of appendix A to part 60, must be sampled at least once during each test run;

(iii) In order to distribute the sampling time most evenly over all the traverse points, do not perform all runs using the same sampling point order (*e.g.*, if there are four ports and sampling for run 1 began in port 1, then sampling for run 2 could begin in port 4 and continue in reverse order.)

* * * * *

(6) Apply paragraphs (b)(1) through (5) of this section for each pollutant separately if a different production rate, charge material or, if applicable, reactive fluxing rate would apply and thereby result in a higher expected emissions rate for that pollutant.

(7) The owner or operator may not conduct performance tests during periods of malfunction.

(c) * * *

(9) Method 26A for the concentration of HCl and HF. Method 26 may also be used, except at sources where entrained water droplets are present in the emission stream. Where a lime-injected fabric filter is used as the control device to comply with the 90 percent reduction standard, the owner or operator must measure the fabric filter inlet concentration of HCl at a point before lime is introduced to the system.

(d) *Alternative methods.* The owner or operator may use alternative test methods as provided in paragraphs (d)(1) through (3) of this section.

(1) The owner or operator may use test method ASTM D7520–13 as an alternative to EPA Method 9 subject to conditions described in § 63.1510(f)(4).

(2) In lieu of conducting the annual flow rate measurements using Methods 1 and 2, the owner or operator may use Method 204 in Appendix M to 40 CFR part 51 to conduct annual verification of a permanent total enclosure for the affected source/emission unit.

(3) The owner or operator may use an alternative test method approved by the Administrator.

* * * * *

(f) *Testing of representative emission units.* With the prior approval of the permitting authority for major sources, or the Administrator for area sources, an owner or operator may utilize emission rates obtained by testing a particular type of group 1 furnace that does not have an add-on air pollution control device, or by testing an in-line flux box that does not have an add-on air pollution control device, to determine the emission rate for other units of the same type at the same facility. Such emission test results may only be considered to be representative of other units if all of the following criteria are satisfied:

* * * * *

(6) All 3 separate runs of a performance test must be conducted on the same emission unit.

(g) *Establishment of monitoring and operating parameter values.* The owner or operator of new or existing affected sources and emission units must establish a minimum or maximum operating parameter value, or an operating parameter range for each parameter to be monitored as required by § 63.1510 that ensures compliance with the applicable emission limit or standard. To establish the minimum or maximum value or range, the owner or operator must use the appropriate procedures in this section and submit the information required by § 63.1515(b)(4) in the notification of compliance status report. The owner or operator may use existing data in addition to the results of performance tests to establish operating parameter values for compliance monitoring provided each of the following conditions are met to the satisfaction of the permitting authority for major sources, or the Administrator for area sources:

* * * * *

(5) If the owner or operator wants to conduct a new performance test and establish different operating parameter values, they must submit a revised site specific test plan and receive approval in accordance with paragraph (a) of this section. In addition, if an owner or operator wants to use existing data in addition to the results of the new performance test to establish operating parameter values, they must meet the requirements in paragraphs (g)(1) through (4) of this section.

* * * * *

(i) Testing of commonly-ducted units not within a secondary aluminum processing unit. With the prior approval of the permitting authority for major sources, or the Administrator for area sources, an owner or operator may do combined performance testing of two or more individual affected sources or emission units which are not included in a single existing SAPU or new SAPU, but whose emissions are manifolded to a single control device. Any such performance testing of commonly-ducted units must satisfy the following basic requirements:

* * * * *

■ 10. Section 63.1512 is amended by:

■ a. Revising paragraphs (a), (e)(1) through (3);

■ b. Adding paragraphs (e)(4) through (7); and

■ c. Revising paragrpahs (h)(2), (j) introductory text, (j)(1)(i), (j)(2)(i), (o) introductory text, (o)(1), (o)(3) through (5), and (p)(2).

The additions and revisions read as follows:

§ 63.1512 Performance test/compliance demonstration requirements and procedures.

(a) *Aluminum scrap shredder.* The owner or operator must conduct performance tests to measure PM emissions at the outlet of the control system. If visible emission observation is the selected monitoring option, the owner or operator must record visible emission observations from each exhaust stack for all consecutive 6-minute periods during the PM emission test according to the requirements of Method 9 in appendix A to 40 CFR part 60. If emissions observations by ASTM Method D7520–13 (incorporated by reference, see § 63.14) is the selected monitoring option, the owner or operator must record opacity observations from each exhaust stack for all consecutive 6-minute periods during the PM emission test.

* * * * *

(e) * * *

(1) If the group 1 furnace processes other than clean charge material, the owner or operator must conduct emission tests to measure emissions of PM, HCl, HF, and D/F at the furnace exhaust outlet.

(2) If the group 1 furnace processes only clean charge, the owner or operator must conduct emission tests to simultaneously measure emissions of PM, HCl and HF. A D/F test is not required. Each test must be conducted while the group 1 furnace (including a melting/holding furnace) processes only clean charge.

(3) The owner or operator may choose to determine the rate of reactive flux addition to the group 1 furnace and assume, for the purposes of demonstrating compliance with the SAPU emission limit, that all chlorine and fluorine contained in reactive flux added to the group 1 furnace is emitted as HCl and HF. Under these circumstances, the owner or operator is not required to conduct an emission test for HCl or HF.

(4) When testing an existing uncontrolled furnace, the owner or operator must comply with the requirements of either paragraphs (e)(4)(i), (ii) or (iii) of this section at the next required performance test required by § 63.1511(e).

(i) Install hooding that meets ACGIH Guidelines (incorporated by reference, see § 63.14), or

(ii) At least 180 days prior to testing petition the permitting authority for major sources, or the Administrator for area sources, that such hoods are impractical under the provisions of paragraph (e)(6) of this section and propose testing procedures that will minimize unmeasured emissions during the performance test according to the paragraph (e)(7) of this section, or

(iii) Assume an 80-percent capture efficiency for the furnace exhaust (i.e., multiply emissions measured at the furnace exhaust outlet by 1.25). If the source fails to demonstrate compliance using the 80-percent capture efficiency assumption, the owner or operator must re-test with a hood that meets the ACGIH Guidelines within 180 days, or petition the permitting authority for major sources, or the Administrator for area sources, within 180 days that such hoods are impractical under the provisions of paragraph (e)(6) of this section and propose testing procedures that will minimize unmeasured emissions during the performance test according to paragraph (e)(7) of this section.

(iv) The 80-percent capture efficiency assumption is not applicable in the event of testing conducted under an approved petition submitted pursuant to paragraphs (e)(4)(ii) or (iii) of this section.

(v) Round top furnaces constructed before February 14, 2012, and reconstructed round top furnaces are exempt from the requirements of paragraphs (e)(4)(i) and (ii) of this section. Round top furnaces must be operated to minimize unmeasured emissions according to paragraph (e)(7) of this section.

(5) When testing a new uncontrolled furnace constructed after February 14, 2012, the owner or operator must install hooding that meets ACGIH Guidelines (incorporated by reference, see § 63.14) or petition the permitting authority for major sources, or the Administrator for area sources, that such hoods are impracticable under the provisions of paragraph (e)(6) of this section and propose testing procedures that will minimize unmeasured emissions during the performance test according to the provisions of paragraph (e)(7).

(6) The installation of hooding that meets ACGIH Guidelines (incorporated by reference, see § 63.14) is considered impractical if any of the following conditions exist:

(i) Building or equipment obstructions (for example, wall, ceiling, roof, structural beams, utilities, overhead crane or other obstructions) are present such that the temporary hood cannot be located consistent with acceptable hood design and installation practices;

(ii) Space limitations or work area constraints exist such that the temporary hood cannot be supported or located to prevent interference with normal furnace operations or avoid unsafe working conditions for the furnace operator; or

(iii) Other obstructions and limitations subject to agreement of the permitting authority for major sources, or the Administrator for area sources.

(7) Testing procedures that will minimize unmeasured emissions may include, but are not limited to the following:

(i) Installing a hood that does not entirely meet ACGIH guidelines;

(ii) Using the building as an enclosure, and measuring emissions exhausted from the building if there are no other furnaces or other significant sources in the building of the pollutants to be measured;

(iii) Installing temporary baffles on those sides or top of furnace opening if it is practical to do so where they will not interfere with material handling or with the furnace door opening and closing;

(iv) Minimizing the time the furnace doors are open or the top is off;

(v) Delaying gaseous reactive fluxing until charging doors are closed and, for round top furnaces, until the top is on;

(vi) Agitating or stirring molten metal as soon as practicable after salt flux addition and closing doors as soon as possible after solid fluxing operations, including mixing and dross removal;

(vii) Keeping building doors and other openings closed to the greatest extent possible to minimize drafts that would divert emissions from being drawn into the furnace;

(viii) Maintaining burners on low-fire or pilot operation while the doors are open or the top is off;

(ix) Use of fans or other device to direct flow into a furnace when door is open; or

(x) Removing the furnace cover one time in order to add a smaller but representative charge and then replacing the cover.

* * * * *

(h) * * *

(2) The owner or operator may choose to limit the rate at which reactive flux is added to an in-line fluxer and assume, for the purposes of demonstrating compliance with the SAPU emission limit, that all chlorine in the reactive flux added to the in-line fluxer is emitted as HCl. Under these circumstances, the owner or operator is not required to conduct an emission test for HCl. If the owner or operator of any in-line flux box that has no ventilation ductwork manifolded to any outlet or emission control device chooses to demonstrate compliance with the emission limits for HCl by limiting use of reactive flux and assuming that all chlorine in the flux is emitted as HCl, compliance with the HCl limit shall also constitute compliance with the emission limit for PM and no separate emission test for PM is required. In this case, the owner or operator of the unvented in-line flux box must use the maximum permissible PM emission rate for the in-line flux boxes when determining the total emissions for any SAPU which includes the flux box.

* * * * *

(j) *Secondary aluminum processing unit.* The owner or operator must conduct performance tests as described in paragraphs (j)(1) through (3) of this section. The results of the performance tests are used to establish emission rates in lb/ton of feed/charge for PM, HCl and HF and µg TEQ/Mg of feed/charge for D/F emissions from each emission unit. These emission rates are used for compliance monitoring in the calculation of the 3-day, 24-hour rolling average emission rates using the equation in § 63.1510(t). A performance test is required for:

(1) * * *

(i) Emissions of HF and HCl (for determining the emission limit); or

* * * * *

(2) * * *

(i) Emissions of HF and HCl (for determining the emission limit); or

* * * * *

(o) *Flux injection rate.* The owner or operator must use these procedures to establish an operating parameter value or range for the total reactive chlorine flux injection rate and, for uncontrolled furnaces, the total reactive fluorine flux injection rate.

(1) Continuously measure and record the weight of gaseous or liquid reactive flux injected for each 15 minute period during the HCl, HF and D/F tests, determine and record the 15-minute block average weights, and calculate and record the total weight of the gaseous or liquid reactive flux for the 3 test runs;

* * * * *

(3) Determine the total reactive chlorine flux injection rate and, for uncontrolled furnaces, the total reactive fluorine flux injection rate by adding the recorded measurement of the total weight of chlorine and, for uncontrolled furnaces, fluorine in the gaseous or liquid reactive flux injected and the total weight of chlorine and, for uncontrolled furnaces, fluorine in the solid reactive flux using Equation 5:

$$W_t = F_1 W_1 + F_2 W_2 \qquad \text{(Eq. 5)}$$

Where:

W_t = Total chlorine or fluorine usage, by weight;

F_1 = Fraction of gaseous or liquid flux that is chlorine or fluorine;

W_1 = Weight of reactive flux gas injected;

F_2 = Fraction of solid reactive chloride flux that is chlorine (*e.g.*, F = 0.75 for magnesium chloride) or fraction of solid reactive fluoride flux that is fluorine (*e.g.*, F = 0.33 for potassium fluoride); and

W_2 = Weight of solid reactive flux;

(4) Divide the weight of total chlorine or fluorine usage (W_t) for the 3 test runs by the recorded measurement of the total weight of feed for the 3 test runs; and

(5) If a solid reactive flux other than magnesium chloride or potassium fluoride is used, the owner or operator must derive the appropriate proportion factor subject to approval by the permitting authority for major sources, or the Administrator for area sources.

* * * * *

(p) * * *

(2) Record the feeder setting and lime injection rate for the 3 test runs. If the feed rate setting and lime injection rates vary between the runs, determine and record the average feed rate and lime injection rate from the 3 runs.

* * * * *

■ 11. Section 63.1513 is amended by revising the paragraph (b) heading and paragraphs (b)(1), (d), and (e)(1) through (3), and adding paragraph (f) to read as follows:

§ 63.1513 Equations for determining compliance.

* * * * *

(b) *PM, HCl, HF and D/F emission limits.* (1) Use Equation 7 of this section to determine compliance with an emission limit for PM, HCl or HF:

$$E = \frac{C \times Q \times K_1}{P} \qquad \text{(Eq. 7)}$$

Where:

E = Emission rate of PM, HCl or HF, in kg/Mg (lb/ton) of feed;

C = Concentration of PM, HCl or HF, in g/dscm (gr/dscf);

Q = Volumetric flow rate of exhaust gases, in dscm/hr (dscf/hr);

K_1 = Conversion factor, 1 kg/1,000 g (1 lb/7,000 gr); and

P = Production rate, in Mg/hr (ton/hr).

* * * * *

(d) *Conversion of D/F measurements to TEQ units.* To convert D/F measurements to TEQ units, the owner or operator must use the procedures and equations in *Interim Procedures for Estimating Risks Associated with Exposures to Mixtures of Chlorinated Dibenzo-p-Dioxins and -Dibenzofurans (CDDs and CDFs) and 1989 Update*, incorporated by reference see § 63.14.

(e) * * *

(1) Use Equation 9 to compute the mass-weighted PM emissions for a secondary aluminum processing unit. Compliance is achieved if the mass-weighted emissions for the secondary aluminum processing unit (E_{cPM}) is less than or equal to the emission limit for the secondary aluminum processing unit (L_{cPM}) calculated using Equation 1 in § 63.1505(k).

$$E_{C_{PM}} = \frac{\sum_{i=1}^{n}\left(E_{ti_{PM}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \qquad \text{(Eq. 9)}$$

Where:

E_{cPM} = The mass-weighted PM emissions for the secondary aluminum processing unit;

E_{tiPM} = Measured PM emissions for individual emission unit, or group of co-controlled emission units, i;

T_{ti} = The average feed rate for individual emission unit i during the operating cycle or performance test period, or the sum of the average feed rates for all emission units in the group of co-controlled emission units i; and

n = The number of emission units, and groups of co-controlled emission units in the secondary aluminum processing unit.

(2) Use Equation 10 to compute the aluminum mass-weighted HCl or HF emissions for the secondary aluminum processing unit. Compliance is achieved if the mass-weighted emissions for the secondary aluminum processing unit ($E_{cHCl/HF}$) is less than or equal to the emission limit for the secondary aluminum processing unit ($L_{cHCl/HF}$) calculated using Equation 2 in § 63.1505(k).

$$E_{C_{HCl/HF}} = \frac{\sum_{i=1}^{n}\left(E_{ti_{HCl/HF}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \quad \text{(Eq. 10)}$$

Where:

$E_{cHCl/HF}$ = The mass-weighted HCl or HF emissions for the secondary aluminum processing unit; and

$E_{tiHCl/HF}$ = Measured HCl or HF emissions for individual emission unit, or group of co-controlled emission units i.

(3) Use Equation 11 to compute the aluminum mass-weighted D/F emissions for the secondary aluminum processing unit. Compliance is achieved if the mass-weighted emissions for the secondary aluminum processing unit is less than or equal to the emission limit for the secondary aluminum processing unit ($L_{cD/F}$) calculated using Equation 3 in § 63.1505(k).

$$E_{C_{D/F}} = \frac{\sum_{i=1}^{n}\left(E_{ti_{D/F}} \times T_{ti}\right)}{\sum_{i=1}^{n}\left(T_{ti}\right)} \quad \text{(Eq. 11)}$$

Where:

$E_{cD/F}$ = The mass-weighted D/F emissions for the secondary aluminum processing unit; and

$E_{tiD/F}$ = Measured D/F emissions for individual emission unit, or group of co-controlled emission units i.

* * * * *

(f) *Periods of startup and shutdown.* For a new or existing affected source, or a new or existing emission unit subject to an emissions limit in paragraphs § 63.1505(b) through (j) expressed in units of pounds per ton of feed/charge, or µg TEQ or ng TEQ per Mg of feed/charge, demonstrate compliance during periods of startup and shutdown in accordance with paragraph (f)(1) of this section or determine your emissions per unit of feed/charge during periods of startup and shutdown in accordance with paragraph (f)(2) of this section. Startup and shutdown emissions for group 1 furnaces and in-line fluxers must be calculated individually, and not on the basis of a SAPU. Periods of startup and shutdown are excluded from the calculation of SAPU emission limits in § 63.1505(k), the SAPU monitoring requirements in § 63.1510(t) and the SAPU emissions calculations in § 63.1513(e).

(1) For periods of startup and shutdown, records establishing a feed/charge rate of zero, a flux rate of zero, and that the affected source or emission unit was either heated with electricity, propane or natural gas as the sole sources of heat or was not heated, may be used to demonstrate compliance with the emission limit, or

(2) For periods of startup and shutdown, divide your measured emissions in lb/hr or µg/hr or ng/hr by the feed/charge rate in tons/hr or Mg/hr from your most recent performance test associated with a production rate greater than zero, or the rated capacity of the affected source if no prior performance test data is available.

■ 12. Section 63.1514 is added to read as follows:

§ 63.1514 Change of Furnace Classification.

The requirements of this section are in addition to the other requirements of this subpart that apply to group 1 and group 2 furnaces.

(a) *Changing from a group 1 controlled furnace processing other than clean charge to group 1 uncontrolled furnace processing other than clean charge.* An owner or operator wishing to change operating modes must conduct performance tests in accordance with §§ 63.1511 and 63.1512 to demonstrate to the permitting authority for major sources, or the Administrator for area sources that compliance can be achieved under both modes. Operating parameters relevant to each mode of operation must be established during the performance test.

(1) Operators of major sources must conduct performance tests for PM, HCl and D/F, according to the procedures in § 63.1512(d) with the capture system and control device operating normally if compliance has not been previously demonstrated in this operating mode. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in the controlled mode.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(2) Operators of major sources must conduct performance tests for PM, HCl, HF and D/F, according to the procedures in § 63.1512(e) without operating a control device if compliance has not been previously demonstrated for this operating mode. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in the uncontrolled mode.

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Operating parameters representing uncontrolled operation must be established during these tests, as required by § 63.1511(g). For furnaces in batch (cyclic) operation, the number of tap-to-tap cycles (including zero, if none) elapsed using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode. For furnaces in continuous (non-cyclic) operation, the time period elapsed (including no time, if none) using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode.

(iv) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(3) Operators of area sources must conduct performance tests for D/F, according to the procedures in § 63.1512(d) with the capture system and control device operating normally, if compliance has not been previously demonstrated for this operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in the controlled mode.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The D/F emission factor for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(4) Operators of area sources must conduct performance tests for D/F, according to the procedures in § 63.1512(e) without operating a control device, if compliance has not been previously demonstrated for this operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1).

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Operating parameters representing uncontrolled operation must be established during these tests, as required by § 63.1511(g). For furnaces in batch (cyclic) operation, the number of tap-to-tap cycles (including zero, if none) elapsed using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode. For furnaces in continuous (non-cyclic) operation, the time period elapsed (including no time, if none) using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode.

(iv) The D/F emission factor for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(5) To change modes of operation from uncontrolled to controlled, the owner or operator must perform the following, before charging scrap to the furnace that exceeds the contaminant level established for uncontrolled mode:

(i) Change the label on the furnace to reflect controlled operation;

(ii) Direct the furnace emissions to the control device;

(iii) Turn on the control device and begin lime addition to the control device at the rate established for controlled mode; and

(iv) Ensure the control device is operating properly.

(6) To change modes of operation from controlled to uncontrolled, the owner or operator must perform the following, before turning off or bypassing the control device:

(i) Change the label on the furnace to reflect uncontrolled operation;

(ii) Charge scrap with a level of contamination no greater than that used in the performance test for uncontrolled furnaces for the number of tap-to-tap cycles that elapsed (or, for continuously operated furnaces, the time elapsed) before the uncontrolled mode performance test was conducted; and

(iii) Decrease the flux addition rate to no higher than the flux addition rate used in the uncontrolled mode performance test.

(7) In addition to the recordkeeping requirements of § 63.1517, the owner or operator must maintain records of the nature of each mode change (controlled to uncontrolled, or uncontrolled to controlled), the time the change is initiated, and the time the exhaust gas is diverted from control device to bypass or bypass to control device.

(b) *Changing from a group 1 controlled furnace processing other than clean charge to a group 1 uncontrolled furnace processing clean charge.* An owner or operator wishing to change operating modes must conduct performance tests in accordance with §§ 63.1511 and 63.1512 to demonstrate to the permitting authority for major sources, or the Administrator for area sources that compliance can be achieved in both modes. Operating parameters relevant to each mode of operation must be established during the performance test.

(1) Operators of major sources must conduct performance tests for PM, HCl and D/F, according to the procedures in § 63.1512(d) with the capture system and control device operating normally if compliance has not been previously demonstrated in this operating mode. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in the controlled mode.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(2) Operators of major sources must conduct performance tests for PM, HCl, HF and D/F, according to the procedures in § 63.1512(e) without operating a control device if compliance has not been previously demonstrated for this operating mode. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph may be conducted at any time after operation with clean charge has commenced.

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Operating parameters representing uncontrolled operation must be established during these tests, as required by § 63.1511(g). For furnaces in batch (cyclic) operation, the number of tap-to-tap cycles (including zero, if none) elapsed using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode. For furnaces in continuous (non-cyclic) operation, the time period elapsed (including no time if none) using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode.

(iv) Emissions of D/F during this test must not exceed 1.5 µg TEQ/Mg of feed/charge.

(v) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k), must be determined.

(3) Operators of area sources must conduct performance tests for D/F, according to the procedures in § 63.1512(d) with the capture system and control device operating normally, if compliance has not been previously demonstrated for this operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1).

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The D/F emission factor for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(4) Operators of area sources must conduct performance tests for D/F, according to the procedures in § 63.1512(e) without operating a control device if compliance has not been previously demonstrated for this operating mode.

(i) Testing under this paragraph must be conducted at any time after operation with clean charge has commenced and must be conducted in accordance with § 63.1511(b)(1) and under representative conditions expected to produce the highest level of D/F in the uncontrolled mode.

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Operating parameters representing uncontrolled operation must be established during these tests, as required by § 63.1511(g). For furnaces in batch (cyclic) operation, the number of tap-to-tap cycles elapsed (including zero, if none) using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode. For furnaces in continuous (non-cyclic) operation, the time period elapsed (including no time, if none) using the feed/charge type, feed/charge rate and flux rate must be established as a parameter to be met before changing to uncontrolled mode.

(iv) Emissions of D/F during this test must not exceed 1.5 μg TEQ/Mg of feed/charge.

(5) To change modes of operation from uncontrolled to controlled, the owner or operator must perform the following, before charging scrap to the furnace that exceeds the contaminant level established for uncontrolled mode:

(i) Change the label on the furnace to reflect controlled operation;

(ii) Direct the furnace emissions to the control device;

(iii) Turn on the control device and begin lime addition to the control device at the rate established for controlled mode; and

(iv) Ensure the control device is operating properly.

(6) To change modes of operation from controlled to uncontrolled, the owner or operator must perform the following, before turning off or bypassing the control device:

(i) Change the label on the furnace to reflect uncontrolled operation;

(ii) Charge clean charge for the number of tap-to-tap cycles that elapsed (or, for continuously operated furnaces, the time elapsed) before the uncontrolled mode performance test was conducted; and

(iii) Decrease the flux addition rate to no higher than the flux addition rate used in the uncontrolled mode performance test.

(7) In addition to the recordkeeping requirements of § 63.1517, the owner or operator must maintain records of the nature of each mode change (controlled to uncontrolled, or uncontrolled to controlled), the time the furnace operating mode change is initiated, and the time the exhaust gas is diverted from control device to bypass or from bypass to control device.

(c) *Changing from a group 1 controlled or uncontrolled furnace to a group 2 furnace.* An owner or operator wishing to change operating modes must conduct performance tests in accordance with §§ 63.1511 and 63.1512 to demonstrate to the permitting authority for major sources, or the Administrator for area sources that compliance can be achieved under both modes and establish the number of cycles (or time) of operation with clean charge and no reactive flux addition necessary before changing to group 2 mode. Operating parameters relevant to group 1 operation must be established during the performance test.

(1) Operators of major sources must conduct performance tests for PM, HCl and D/F (and HF for uncontrolled group 1 furnaces) according to the procedures in § 63.1512 if compliance has not been previously demonstrated for the operating mode. Controlled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(d) with the capture system and control device operating normally. Uncontrolled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(e) without operating a control device. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in both modes.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(2) While in compliance with the operating requirements of § 63.1506(o) for group 2 furnaces, operators of major sources must conduct performance tests for PM, HCl, HF and D/F, according to the procedures in § 63.1512(e) without operating a control device if compliance has not been previously demonstrated for this operating mode. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph may be conducted at any time after the furnace has commenced operation with clean charge and without reactive flux addition.

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Owners or operators must demonstrate that emissions are no greater than:

(A) 1.5 μg D/F (TEQ) per Mg of feed/charge;

(B) 0.040 lb HCl or HF per ton of feed/charge; and

(C) 0.040 lb PM per ton of feed/charge.

(iv) The number of tap-to-tap cycles, or time elapsed between starting operation with clean charge and no reactive flux addition and the group 2 furnace performance test must be established as an operating parameter to be met before changing to group 2 mode.

(3) Operators of area sources must conduct a performance tests for D/F, according to the procedures in § 63.1512 if compliance has not been previously demonstrated for the operating mode. Controlled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(d) with the capture system and control device operating normally. Uncontrolled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(e) without operating a control device.

(i) The performance tests must be conducted in accordance with § 63.1511(b)(1) under representative conditions expected to produce the highest expected level of D/F in the group 1 mode.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The D/F emission factor for this mode of operation, for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(4) While in compliance with the operating requirements of § 63.1506(o) for group 2 furnaces, operators of area sources must conduct performance tests for D/F, according to the procedures in § 63.1512(e) without operating a control device if compliance has not been previously demonstrated for this operating mode.

(i) Testing under this paragraph may be conducted at any time after the furnace has commenced operation with clean charge, and without reactive flux addition.

(ii) Testing under this paragraph must be conducted with furnace emissions captured in accordance with the provisions of § 63.1506(c) and directed to the stack or vent tested.

(iii) Owners or operators must demonstrate that emissions are no greater than 1.5 μg D/F (TEQ) per Mg of feed/charge.

(iv) The number of tap-to-tap cycles, or time elapsed between starting operation with clean charge and no reactive flux and the group 2 furnace performance tests must be established as an operating parameter to be met before changing to group 2 mode.

(5) To change modes of operation from a group 2 furnace to a group 1 furnace, the owner or operator must perform the following before adding other than clean charge and before adding reactive flux to the furnace:

(i) Change the label on the furnace to reflect group 1 operation;

(ii) Direct the furnace emissions to the control device, if it is equipped with a control device;

(iii) If the furnace is equipped with a control device, turn on the control device and begin lime addition to the control device at the rate established for group 1 mode; and

(iv) Ensure the control device is operating properly.

(6) To change mode of operation from a group 1 furnace to group 2 furnace, the owner or operator must perform the following, before turning off or bypassing the control device:

(i) Change the label on the furnace to reflect group 2 operation;

(ii) Charge clean charge for the number of tap-to-tap cycles that elapsed (or, for continuously operated furnaces, the time elapsed) before the group 2 performance test was conducted; and,

(iii) Use no reactive flux.

(7) In addition to the recordkeeping requirements of § 63.1517, the owner or operator must maintain records of the nature of each mode change (controlled or uncontrolled to group 2), the time the change is initiated, and the time the exhaust gas is diverted from control device to bypass or from bypass to control device.

(d) *Changing from a group 1 controlled or uncontrolled furnace to group 2 furnace, for tilting reverberatory furnaces capable of completely removing furnace contents between batches.* An owner or operator of a tilting reverberatory furnace capable of completely removing furnace contents between batches who wishes to change operating modes must conduct performance tests in accordance with §§ 63.1511 and 63.1512 to demonstrate to the permitting authority for major sources, or the Administrator for area sources that compliance can be achieved under group 1 modes. Operating parameters relevant to group 1 operation must be established during the performance test.

(1) Operators of major sources must conduct performance tests for PM, HCl, and D/F (and HF for uncontrolled furnaces) according to the procedures in § 63.1512 if compliance has not been previously demonstrated for this operating mode. Controlled group 1 furnaces must conduct performance tests with the capture system and control device operating normally if compliance has not been previously demonstrated for the operating mode. Controlled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(d) with the capture system and control device operating normally. Uncontrolled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(e) without operating a control device. Performance tests must be repeated at least once every 5 years to demonstrate compliance for each operating mode.

(i) Testing under this paragraph must be conducted in accordance with § 63.1511(b)(1) in both modes.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The emission factors for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k), must be determined.

(2) Operators of area sources must conduct performance tests for D/F according to the procedures in § 63.1512 if compliance has not been previously demonstrated for this operating mode. Controlled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(d) with the capture system and control device operating normally. Uncontrolled group 1 furnaces must conduct performance tests according to the procedures in § 63.1512(e) without operating a control device.

(i) The performance test must be conducted in accordance with § 63.1511(b)(1) under representative conditions expected to produce the highest expected level of D/F in the group 1 mode.

(ii) Operating parameters must be established during these tests, as required by § 63.1511(g).

(iii) The D/F emission factor for this mode of operation for use in the demonstration of compliance with the emission limits for SAPUs specified in § 63.1505(k) must be determined.

(3) To change modes of operation from a group 1 furnace to a group 2 furnace, the owner or operator must perform the following before turning off or bypassing the control device:

(i) Completely remove all aluminum from the furnace;

(ii) Change the label on the furnace to reflect group 2 operation;

(iii) Use only clean charge; and

(iv) Use no reactive flux.

(4) To change modes of operation from a group 2 furnace to a group 1 furnace, the owner or operator must perform the following before adding other than clean charge and before adding reactive flux to the furnace:

(i) Change the label on the furnace to reflect group 1 operation;

(ii) Direct the furnace emissions to the control device, if it is equipped with a control device;,

(iii) If the furnace is equipped with a control device, turn on the control device and begin lime addition to the control device at the rate established for group 1 mode; and

(iv) Ensure the control device is operating properly.

(5) In addition to the recordkeeping requirements of § 63.1517, the owner or operator must maintain records of the nature of each mode change (group 1 to group 2, or group 2 to group 1), the time the furnace operating mode change is initiated, and, if the furnace is equipped with a control device, the time the exhaust gas is diverted from control device to bypass or from bypass to control device.

(e) *Limit on Frequency of changing furnace operating mode.* (1) Changing furnace operating mode including reversion to the previous mode, as provided in paragraphs (a) through (d) of this section, may not be done more frequently than 4 times in any 6-month period unless you receive approval from the permitting authority or Administrator for additional changes pursuant to paragraph (e)(2).

(2) If additional changes are needed, the owner or operator must apply in advance to the permitting authority, for major sources, or the Administrator, for area sources, for approval of the additional changes in operating mode.

■ 13. Section 63.1515 is amended by:

■ a. Revising paragraphs (a) introductory text, and (b)(4); and

■ b. Removing paragraph (b)(10).

The revisions read as follows:

§ 63.1515 Notifications.

(a) *Initial notifications.* The owner or operator must submit initial notifications to the permitting authority for major sources, or the Administrator for area sources as described in paragraphs (a)(1) through (7) of this section.

* * * * *

(b) * * *

(4) The compliant operating parameter value or range established for each affected source or emission unit with supporting documentation and a description of the procedure used to establish the value (e.g., lime injection rate, total reactive chlorine flux injection rate, total reactive fluorine flux injection rate for uncontrolled group 1 furnaces, afterburner operating temperature, fabric filter inlet temperature), including the operating cycle or time period used in the performance test.

* * * * *

■ 14. Section 63.1516 is amended by:

■ a. Removing and reserving paragraph (a);

■ b. Revising paragraph (b) introductory text;

■ c. Removing and reserving paragraph and (b)(1)(v);

■ d. Adding paragraphs (b)(2)(vii) and (b)(3)(i);

■ e. Revising paragraph (c) introductory text; and

■ f. Adding paragraphs (d) and (e).

The additions and revisions read as follows:

§ 63.1516 Reports.

* * * * *

(b) Excess emissions/summary report. The owner or operator of a major or area source must submit semiannual reports according to the requirements in § 63.10(e)(3). Except, the owner or operator must submit the semiannual reports within 60 days after the end of each 6-month period instead of within 30 days after the calendar half as specified in § 63.10(e)(3)(v). When no deviations of parameters have occurred, the owner or operator must submit a report stating that no excess emissions occurred during the reporting period.

* * * * *

(2) * * *

(vii) For each affected source choosing to demonstrate compliance during periods of startup and shutdown in accordance with § 63.1513(f)(1): ''During each startup and shutdown, no flux and no feed/charge were added to the emission unit, and electricity, propane or natural gas were used as the sole source of heat or the emission unit was not heated.''

* * * * *

(3) * * *

(i) Within 60 days after the date of completing each performance test (as defined in § 63.2) required by this subpart, you must submit the results of the performance tests, including any associated fuel analyses, following the procedure specified in either paragraph (b)(3)(i)(A) or (B) of this section.

(A) For data collected using test methods supported by the EPA's Electronic Reporting Tool (ERT) as listed on the EPA's ERT Web site (*http://www.epa.gov/ttn/chief/ert/index.html*), you must submit the results of the performance test to the EPA via the Compliance and Emissions Data Reporting Interface (CEDRI). CEDRI can be accessed through the EPA's Central Data Exchange (CDX) (*http://cdx.epa.gov/epa_home.asp*). Performance test data must be submitted in a file format generated through the use of the EPA's ERT. Alternatively, you may submit performance test data in an electronic file format consistent with the extensible markup language (XML) schema listed on the EPA's ERT Web site once the XML schema is available. If you claim that some of the performance test information being submitted is confidential business information (CBI), you must submit a complete file generated through the use of the EPA's ERT or an alternate electronic file consistent with the XML schema listed on the EPA's ERT Web site, including information claimed to be CBI, on a compact disc, flash drive, or other commonly used electronic storage media to the EPA. The electronic media must be clearly marked as CBI and mailed to U.S. EPA/OAPQS/CORE CBI Office, Attention: Group Leader, Measurement Policy Group, MD C404–02, 4930 Old Page Rd., Durham, NC 27703. The same ERT or alternate file with the CBI omitted must be submitted to the EPA via the EPA's CDX as described earlier in this paragraph.

(B) For data collected using test methods that are not supported by the EPA's ERT as listed on the EPA's ERT Web site, you must submit the results of the performance test to the Administrator at the appropriate address listed in § 63.13.

* * * * *

(c) *Annual compliance certifications.* For the purpose of annual certifications of compliance required by 40 CFR part 70 or 71, the owner or operator of a major source subject to this subpart must certify continuing compliance based upon, but not limited to, the following conditions:

* * * * *

(d) If there was a malfunction during the reporting period, the owner or operator must submit a report that includes the emission unit ID, monitor ID, pollutant or parameter monitored, beginning date and time of the event, end date and time of the event, cause of the deviation or exceedance and corrective action taken for each malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. The report must include a list of the affected source or equipment, an estimate of the quantity of each regulated pollutant emitted over any emission limit, and a description of the method used to estimate the emissions, including, but not limited to, product-loss calculations, mass balance calculations, measurements when available, or engineering judgment based on known process parameters. The report must also include a description of actions taken by an owner or operator during a malfunction of an affected source to minimize emissions in accordance with §§ 63.1506(a)(5) and 63.1520(a)(8).

(e) All reports required by this subpart not subject to the requirements in paragraph (b) 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 paragraph (b) of this section in paper format.

■ 15. Section 63.1517 is amended by:

■ a. By revising paragraphs (b)(1)(iii), (b)(4)(ii), (b)(14);

■ b. By removing and reserving paragraph (b)(16)(i); and

■ c. By adding paragraphs (b)(18) through (20).

The additions and revisions read as follows:

§ 63.1517 Records.

* * * * *

(b) * * *

(1) * * *

(iii) If an aluminum scrap shredder is subject to visible emission observation requirements, records of all Method 9 observations, including records of any visible emissions during a 30-minute daily test or records of all ASTM D7520–13 observations (incorporated by reference, see § 63.14), including data sheets and all raw unaltered JPEGs used for opacity determination, with a brief explanation of the cause of the emissions, the time the emissions occurred, the time corrective action was initiated and completed, and the corrective action taken.

* * * * *

(4) * * *

(ii) If lime feeder setting is monitored, records of daily and monthly inspections of feeder setting, including records of any deviation of the feeder setting from the setting used in the performance test, with a brief explanation of the cause of the deviation and the corrective action taken. If a lime feeder has been repaired or replaced, this action must be documented along with records of the new feeder calibration and the feed mechanism set points necessary to maintain the lb/hr feed rate operating limit. These records must be maintained on site and available upon request.

* * * * *

(14) Records of annual inspections of emission capture/collection and closed vent systems or, if the alternative to the annual flow rate measurements is used, records of differential pressure; fan RPM or fan motor amperage; static pressure measurements; or duct centerline velocity using a hotwire anemometer, ultrasonic flow meter, cross-duct pressure differential sensor, venturi pressure differential monitoring or orifice plate equipped with an associated thermocouple, as appropriate.

* * * * *

(18) For any failure to meet an applicable standard, the owner or operator must maintain the following records;

(i) Records of the emission unit ID, monitor ID, pollutant or parameter monitored, beginning date and time of the event, end date and time of the event, cause of the deviation or exceedance and corrective action taken.

(ii) Records of actions taken during periods of malfunction to minimize emissions in accordance with §§ 63.1506(a)(5) and 63.1520(a)(8), including corrective actions to restore malfunctioning process and air pollution control and monitoring equipment to its normal or usual manner of operation.

(19) For each period of startup or shutdown for which the owner or operator chooses to demonstrate compliance for an affected source, the owner or operator must comply with (b)(19)(i) or (ii) of this section.

(i) To demonstrate compliance based on a feed/charge rate of zero, a flux rate of zero and the use of electricity, propane or natural gas as the sole sources of heating or the lack of heating, the owner or operator must submit a semiannual report in accordance with § 63.1516(b)(2)(vii) or maintain the following records:

(A) The date and time of each startup and shutdown;

(B) The quantities of feed/charge and flux introduced during each startup and shutdown; and

(C) The types of fuel used to heat the unit, or that no fuel was used, during startup and shutdown; or

(ii) To demonstrate compliance based on performance tests, the owner or operator must maintain the following records:

(A) The date and time of each startup and shutdown;

(B) The measured emissions in lb/hr or µg/hr or ng/hr;

(C) The measured feed/charge rate in tons/hr or Mg/hr from your most recent performance test associated with a production rate greater than zero, or the rated capacity of the affected source if no prior performance test data is available; and

(D) An explanation to support that such conditions are considered representative startup and shutdown operations.

(20) For owners or operators that choose to change furnace operating modes, the following records must be maintained:

(i) The date and time of each change in furnace operating mode, and

(ii)The nature of the change in operating mode (for example, group 1 controlled furnace processing other than clean charge to group 2).

* * * * *

16. Table 1 to Subpart RRR of part 63 is revised to read as follows:

Table 1 to Subpart RRR of Part 63—Emission Standards for New and Existing Affected Sources

Affected source/ Emission unit	Polltuant	Limit	Units
All new and existing affected sources and emission units that are controlled with a PM add-on control device and that choose to monitor with a continuous opacity monitor (COM); and all new and existing aluminum scrap shredders that choose to monitor with a COM or to monitor visible emissions	Opacity	10	percent
New and existing aluminum scrap shredder	PM	0.01	gr/dscf
New and existing thermal chip dryer	THC D/F[a]	0.80 2.50	lb/ton of feed µg TEQ/Mg of feed
New and existing scrap dryer/delacquering kiln/decoating kiln Or Alternative limits if afterburner has a design residence time of at least 1 second and operates at a temperature of at least 1400°F	PM HCl THC D/F[a] PM HCl THC D/F[a]	0.08 0.80 0.06 0.25 0.30 1.50 0.20 5.0	lb/ton of feed lb/ton of feed lb/ton of feed µg TEQ/Mg of feed lb/ton of feed lb/ton of feed lb/ton of feed µg TEQ/Mg of feed
New and existing sweat furnace	D/F[a]	0.80	ng TEQ/dscm 11% O_2[b]
New and existing dross-only furnace	PM	0.30	lb/ton of feed
New and existing in-line fluxer[c]	HCl PM	0.04 0.01	lb/ton of feed lb/ton of feed
New and existing in-line fluxer with no reactive fluxing		No Limit	Work practice: no reactive fluxing
New and existing rotary dross cooler	PM	0.04	gr/dscf
New and existing clean furnace (Group 2)		No Limit	Work practices: clean charge only and no reactive fluxing
New and existing group 1 melting/holding furnace (processing only clean charge)[c]	PM HF[h] HCl	0.80 0.40 0.40 or 10	lb/ton of feed lb/ton of feed lb/ton of feed percent of the HCl upstream of the add-on control device
New and existing group 1 furnace[c]	PM HF[h] HCl D/F[a]	0.40 0.40 0.40 or 10 15.0	lb/ton of feed lb/ton of feed lb/ton of feed percent of the HCl upstream of the add-on control device µg TEQ/Mg of feed

Affected source/ Emission unit	Polltuant	Limit	Units
New and existing group 1 furnace with clean charge only[c]	PM HCl HF[h] D/F[a]	0.40 0.40 0.40 or 10 No Limit	lb/ton of feed lb/ton of feed lb/ton of feed percent of the HCl upstream of an add-on control device Clean charge only
New and existing secondary aluminum processing unit[a,d] (consists of all existing group 1 furnaces and existing in-line flux boxes at the facility, or any combination of new group 1 furnaces and new in-line fluxers)	PM[e]	$L_{t_{PM}} = \frac{\sum_{i=1}^{n}\left(L_{i_{PM}} \times T_i\right)}{\sum_{i=1}^{n}\left(T_i\right)}$ (Eq. 1)	
	HCl and HF[f, h]	$L_{t_{HCl/HF}} = \frac{\sum_{i=1}^{n}\left(L_{i_{HCl/HF}} \times T_i\right)}{\sum_{i=1}^{n}\left(T_i\right)}$ (Eq.2)	
	D/F[g]	$L_{t_{D/F}} = \frac{\sum_{i=1}^{n}\left(L_{i_{D/F}} \times T_i\right)}{\sum_{i=1}^{n}\left(T_i\right)}$ (Eq. 3)	

[a] D/F limit applies to a unit at a major or area source.

[b] Sweat furnaces equipped with afterburners meeting the specifications of § 63.1505(f)(1) are not required to conduct a performance test.

[c] These limits are also used to calculate the limits applicable to secondary aluminum processing units.

[d] Equation definitions: L_{iPM} = the PM emission limit for individual emission unit i in the secondary aluminum processing unit [kg/Mg (lb/ton) of feed]; T_i = the feed rate for individual emission unit i in the secondary aluminum processing unit; L_{tPM} = the overall PM emission limit for the secondary aluminum processing unit [kg/Mg (lb-ton) of feed]; $L_{iHCl/HF}$ = the HCl or HF emission limit for individual emission unit i in the secondary aluminum processing unit [kg/Mg (lb/ton) of feed]; $L_{tHCl/HF}$ = the overall HCl or HF emission limit for the secondary aluminum processing unit [kg/Mg (lb/ton) of feed]; $L_{iD/F}$ = the D/F emission limit for individual emission unit i [µg (TEQ)/Mg (gr TEQ/ton) of feed]; $L_{tD/F}$ = the overall D/F emission limit for the secondary aluminum processing unit [µg TEQ/Mg (gr TEQ/ton) of feed]; n = the number of units in the secondary aluminum processing unit.

[e] In-line fluxers using no reactive flux materials cannot be included in this calculation since they are not subject to the PM limit.

[f] In-line fluxers using no reactive flux materials cannot be included in this calculation since they are not subject to the HCl and HF limit. Controlled group 1 furnaces cannot be included in the HF emissions calculation because they are not subject to HF limits.

[g] Clean charge furnaces cannot be included in this calculation since they are not subject to the D/F limit.

[h] HF limits apply only to uncontrolled group 1 furnaces.

■ 17. Table 2 to Subpart RRR of part 63 is amended by:

■ a. Revising the entry ''All affected sources and emission units with an add-on air pollution control device;''

■ b. Revising the entry ''Scrap dryer/delacquering kiln/decoating kiln with afterburner and lime-injected fabric filter;''

■ c. Revising the entry ''In-line fluxer with lime-injected fabric filter (including those that are part of a secondary aluminum processing unit);''

■ d. Revising entry ''Group 1 furnace with lime-injected fabric filter (including those that are part of a secondary of aluminum processing unit);''

■ e. Revising the entry Group 1 furnace without add-on air pollution controls (including those that are part of a secondary aluminum processing unit);

■ f. Revising footnote c to Table 2; and

■ g. Adding footnotes d and e to Table 2.

The revisions and additions read as follows:

TABLE 2 TO SUBPART RRR OF PART 63—SUMMARY OF OPERATING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS

Affected source/emission unit	Monitor type/operation/process	Operating requirements
All affected sources and emission units with an add-on air pollution control device.	Emission capture and collection system.	Design and install in accordance with ACGIH Guidelines;[e] operate in accordance with OM&M plan (sweat furnaces may be operated according to 63.1506(c)(4)).[b]
* *	* *	* * *
Scrap dryer/delacquering kiln/decoating kiln with afterburner and lime-injected fabric filter.	Afterburner operating temperature	Maintain average temperature for each 3-hr period at or above average operating temperature during the performance test.
	Afterburner operation	Operate in accordance with OM&M plan.[b]
	Bag leak detector or	Initiate corrective action within 1-hr of alarm and complete in accordance with the OM&M plan;[b] operate such that alarm does not sound more than 5% of operating time in 6-month period.
	COM	Initiate corrective action within 1-hr of a 6-minute average opacity reading of 5% or more and complete in accordance with the OM&M plan.[b]
	Fabric filter inlet temperature	Maintain average fabric filter inlet temperature for each 3-hr period at or below average temperature during the performance test +14 °C (+25 °F).
	Lime injection rate	Maintain free-flowing lime in the feed hopper or silo at all times for continuous injection systems; maintain feeder setting at or above the level established during the performance test for continuous injection systems.
* *	* *	* * *
In-line fluxer with lime-injected fabric filter (including those that are part of a secondary aluminum processing unit).	Bag leak detector or	Initiate corrective action within 1-hr of alarm and complete in accordance with the OM&M plan;[b] operate such that alarm does not sound more than 5% of operating time in 6-month period.
	COM	Initiate corrective action within 1-hr of a 6-minute average opacity reading of 5% or more and complete in accordance with the OM&M plan.[b]
	Lime injection rate	Maintain free-flowing lime in the feed hopper or silo at all times for continuous injection systems; maintain feeder setting at or above the level established during performance test for continuous injection systems.
	Reactive flux injection rate	Maintain reactive flux injection rate at or below rate used during the performance test for each operating cycle or time period used in the performance test.
* *	* *	* * *
Group 1 furnace with lime-injected fabric filter (including those that are part of a secondary of aluminum processing unit).	Bag leak detector or	Initiate corrective action within 1-hr of alarm; operate such that alarm does not sound more than 5% of operating time in 6-month period; complete corrective action in accordance with the OM&M plan.[b]
	COM	Initiate corrective action within 1-hr of a 6-minute average opacity reading of 5% or more; complete corrective action in accordance with the OM&M plan.[b]
	Fabric filter inlet temperature	Maintain average fabric filter inlet temperature for each 3-hour period at or below average temperature during the performance test +14° C (+25° F).
	Natural gas-fired, propane-fired or electrically heated group 1 furnaces that will be idled for at least 24 hours.	Operation of associated capture/collection systems and APCD[b] may be temporarily stopped. Operation of these capture/collection systems and control devices must be restarted before feed/charge, flux or alloying materials are added to the furnace.
	Reactive flux injection rate	Maintain reactive flux injection rate (kg/Mg) (lb/ton) at or below rate used during the performance test for each furnace cycle.

TABLE 2 TO SUBPART RRR OF PART 63—SUMMARY OF OPERATING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS—Continued

Affected source/emission unit	Monitor type/operation/process	Operating requirements
	Lime injection rate	Maintain free-flowing lime in the feed hopper or silo at all times for continuous injection systems; maintain feeder setting at or above the level established at performance test for continuous injection systems.
	Maintain molten aluminum level	Operate sidewell furnaces such that the level of molten metal is above the top of the passage between sidewell and hearth during reactive flux injection, unless the hearth is also controlled.
	Fluxing in sidewell furnace hearth	Add reactive flux only to the sidewell of the furnace unless the hearth is also controlled.
Group 1 furnace without add-on air pollution controls (including those that are part of a secondary aluminum processing unit).	Reactive flux injection rate	Maintain the total reactive chlorine flux injection rate and total reactive fluorine injection rate for each operating cycle or time period used in the performance test at or below the average rate established during the performance test.
	Site-specific monitoring plan.[c]	Operate each furnace in accordance with the work practice/pollution prevention measures documented in the OM&M plan and within the parameter values or ranges established in the OM&M plan.
	Feed material(melting/holding furnace).	Use only clean charge.

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[c] Site-specific monitoring plan. Owner/operators of group 1 furnaces without add-on APCD must include a section in their OM&M plan that documents work practice and pollution prevention measures, including procedures for scrap inspection, by which compliance is achieved with emission limits and process or feed parameter-based operating requirements. This plan and the testing to demonstrate adequacy of the monitoring plan must be developed in coordination with and approved by the permitting authority for major sources, or the Administrator for area sources.

[d] APCD—Air pollution control device.

[e] Incorporated by reference, see § 63.14.

■ 18. Table 3 to Subpart RRR of part 63 is amended by:

■ a. Revising the entry ''All affected sources and emission units with an add-on air pollution control device;''

■ b. Revising the entry ''All affected sources and emission units subject to production-based (lb/ton of feed/charge) emission limits;''

■ c. Revising the entry ''Aluminum scrap shredder with fabric filter;''

■ d. Revising the entry ''Scrap dryer/delacquering kiln/decoating kiln with afterburner and lime-injected fabric filter;''

■ e. Revising entry ''Dross-only furnace with fabric filter;''

■ f. Revising the entry ''Rotary dross cooler with fabric filter;''

■ g. Revising the entry ''In-line fluxer with lime-injected fabric filter;''

■ h. Revising the entry ''Group 1 furnace with lime-injected fabric filter;''

■ i. Revise entry ''Group 1 furnace without add-on controls;''

■ j. Revise footnote c to Table 3;

■ k. Revising footnote d to Table 3; and

■ l. Adding footnote e to Table 3.

The revisions and additions read as follows:

TABLE 3 TO SUBPART RRR OF PART 63—SUMMARY OF MONITORING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS

Affected source/ emission unit	Monitor type/ operation/process	Monitoring requirements
All affected sources and emission units with an add-on air pollution control device.	Emission capture and collection system.	Annual inspection of all emission capture, collection, and transport systems to ensure that systems continue to operate in accordance with ACGIH Guidelines.[e] Inspection includes volumetric flow rate measurements or verification of a permanent total enclosure using EPA Method 204.[d]
All affected sources and emission units subject to production-based (lb/ton or gr/ton of feed/charge) emission limits.[a].	Feed/charge weight	Record weight of each feed/charge, weight measurement device or other procedure accuracy of ± 1%;[b] calibrate according to manufacturer's specifications, or at least once every 6 months.
* * *	* *	* *
Aluminum scrap shredder with fabric filter.	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM or	Design and install in accordance with PS–1; collect data in accordance with subpart A of 40 CFR part 63; determine and record 6-minute block averages.
	VE	Conduct and record results of 30-minute daily test in accordance with Method 9 or ASTM D7520–13.[e]

TABLE 3 TO SUBPART RRR OF PART 63—SUMMARY OF MONITORING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS—Continued

Affected source/ emission unit	Monitor type/ operation/process	Monitoring requirements
* *	* *	* * *
Scrap dryer/delacquering kiln/ decoating kiln with afterburner and lime-injected fabric filter.	Afterburner operating temperature	Continuous measurement device to meet specifications in § 63.1510(g)(1); record temperature for each 15-minute block; determine and record 3-hr block averages.
	Afterburner operation	Annual inspection of afterburner internal parts; complete repairs in accordance with the OM&M plan.
	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM	Design and Install in accordance with PS–1; collect data in accordance with subpart A of 40 CFR part 63; determine and record 6-minute block averages.
	Lime injection rate	For continuous injection systems, inspect each feed hopper or silo every 8 hours to verify that lime is free flowing; record results of each inspection. If blockage occurs, inspect every 4 hours for 3 days; return to 8-hour inspections if corrective action results in no further blockage during 3-day period, record feeder setting daily. Verify monthly that lime injection rate is no less than 90 percent of the rate used during the compliance demonstration test.
	Fabric filter inlet temperature	Continuous measurement device to meet specifications in § 63.1510(h)(2); record temperatures in 15-minute block averages; determine and record 3-hr block averages.
* *	* *	* * *
Dross-only furnace with fabric filter	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM	Design and install in accordance with PS–1; collect data in accordance with subpart A of 40 CFR part 63; determine and record 6-minute block averages.
	Feed/charge material	Record identity of each feed/charge; certify charge materials every 6 months.
Rotary dross cooler with fabric filter.	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM	Design and install in accordance with PS–1; collect data in accordance with subpart A of 40 CFR part 63; determine and record 6-minute block averages.
In-line fluxer with lime-injected fabric filter.	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM	Design and install in accordance with PS–1; collect data in accordance with subpart A of 40 CFR part 63; determine and record 6-minute block averages.
	Reactive flux injection rate	Weight measurement device accuracy of ±1%; [b] calibrate according to manufacturer's specifications or at least once every 6 months; record time, weight and type of reactive flux added or injected for each 15-minute block period while reactive fluxing occurs; calculate and record total reactive chlorine flux injection rate and the total reactive fluorine flux injection rate flux injection rate for each operating cycle or time period used in performance test; or Alternative flux injection rate determination procedure per § 63.1510(j)(5). For solid flux added intermittently, record the amount added for each operating cycle or time period used in the performance test.
	Lime injection rate	For continuous injection systems, record feeder setting daily and inspect each feed hopper or silo every 8 hrs to verify that lime is free-flowing; record results of each inspection. If blockage occurs, inspect every 4 hrs for 3 days; return to 8-hour inspections if corrective action results in no further blockage during 3-day period.[c] Verify monthly that the lime injection rate is no less than 90 percent of the rate used during the compliance demonstration test.
* *	* *	* * *
Group 1 furnace with lime-injected fabric filter.	Bag leak detector or	Install and operate in accordance with manufacturer's operating instructions.
	COM	Design and install in accordance with PS–1; collect data in accordance with subpart A of 40 part CFR 63; determine and record 6-minute block averages.

TABLE 3 TO SUBPART RRR OF PART 63—SUMMARY OF MONITORING REQUIREMENTS FOR NEW AND EXISTING AFFECTED SOURCES AND EMISSION UNITS—Continued

Affected source/ emission unit	Monitor type/ operation/process	Monitoring requirements
	Lime injection rate	For continuous injection systems, record feeder setting daily and inspect each feed hopper or silo every 8 hours to verify that lime is free-flowing; record results of each inspection. If blockage occurs, inspect every 4 hours for 3 days; return to 8-hour inspections if corrective action results in no further blockage during 3-day period.[c] Verify monthly that the lime injection rate is no less than 90 percent of the rate used during the compliance demonstration test.
	Reactive flux injection rate	Weight measurement device accuracy of ±1%;[b] calibrate every 3 months; record weight and type of reactive flux added or injected for each 15-minute block period while reactive fluxing occurs; calculate and record total reactive chlorine flux injection rate and the total reactive fluorine flux injection rate flux injection rate for each operating cycle or time period used in performance test; or Alternative flux injection rate determination procedure per § 63.1510(j)(5). For solid flux added intermittently, record the amount added for each operating cycle or time period used in the performance test.
	Fabric filter inlet temperature	Continuous measurement device to meet specifications in § 63.1510(h)(2); record temperatures in 15-minute block averages; determine and record 3-hour block averages.
	Maintain molten aluminum level in sidewell furnace.	Maintain aluminum level operating log; certify every 6 months. If visual inspection of molten metal level is not possible, use physical measurement methods.
Group 1 furnace without add-on controls.	Fluxing in sidewell furnace hearth	Maintain flux addition operating log; certify every 6 months.
	Reactive flux injection rate	Weight measurement device accuracy of +1%;[b] calibrate according to manufacturer's specifications or at least once every six months; record weight and type of reactive flux added or injected for each 15-minute block period while reactive fluxing occurs; calculate and record total reactive flux injection rate for each operating cycle or time period used in performance test. For solid flux added intermittently, record the amount added for each operating cycle or time period used in the performance test.
	OM&M plan (approved by permitting agency).	Demonstration of site-specific monitoring procedures to provide data and show correlation of emissions across the range of charge and flux materials and furnace operating parameters.
	Feed material (melting/holding furnace).	Record type of permissible feed/charge material; certify charge materials every 6 months.

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[c] Permitting authority for major sources, or the Administrator for area sources may approve other alternatives including load cells for lime hopper weight, sensors for carrier gas pressure, or HCl monitoring devices at fabric filter outlet.

[d] The frequency of volumetric flow rate measurements may be decreased to once every 5 years if daily differential pressure measures, daily fan RPM, or daily fan motor amp measurements are made in accordance with § 63.1510(d)(2)(ii–iii). The frequency of annual verification of a permanent total enclosure may be decreased to once every 5 years if negative pressure measurements in the enclosure are made daily in accordance with § 63.1510(d)(2)(iv). In lieu of volumetric flow rate measurements or verification of permanent total enclosure, sweat furnaces may demonstrate annually negative air flow into the sweat furnace opening in accordance with § 63.1510(d)(3).

[e] Incorporated by reference, see § 63.14.

■ 19. Appendix A to Subpart RRR of part 63 is amended by:
■ a. Revising entry §§ 63.1(a)6)–(8);
■ b. Revising entry § 63.1 (a)(9);
■ c. Revising entry § 63.1(a)(10)–(14);
■ d. Revising entry § 63.1(c)(3);
■ e. Revising entry § 63.1(c)(4)–(5);
■ f. Revising entry § 63.4(a)(1)–(3);
■ g. Revising entry § 63.4(a)(4);
■ h. Removing entry § 63.4(a)(5);
■ i. Revising entry § 63.5(b)(3)–(6);
■ j. Adding entry § 63.5(b)(5);
■ k. Adding entry § 63.5(b)(6);
■ l. Revising entry § 63.6(b)(1)–(5);
■ m. Removing entry § 63.6(e)(1)–(2);
■ n. Adding entry § 63.6(e)(1)(i);
■ o. Adding entry § 63.6(e)(1)ii)
■ p. Adding entry § 63.6(e)(2);
■ q. Revising entry § 63.6(e)(3);
■ r. Removing entry § 63.6(f);
■ s. Adding entry § 63.6(f)(1);
■ t. Adding entries § 63.6(f)(2);
■ u. Removing entries § 63.6(h);
■ v. Adding entries § 63.6(h)(1), § 63.6(h)(2) and § 63.6(h)(3);
■ w. Adding entry § 63.6(h)(4)–(9);
■ x. Revising entry § 63.7(a)–(h);
■ y. Adding entries § 63.7(b), § 63.7(c) and § 63.7(d);
■ z. Removing entry § 63.7((e);
■ aa. Adding entries § 63.7(e)(1) and § 63.7(e)(2);
■ bb. Revising entry § 63.7(g);
■ cc. Revising entry § 63.7(h);
■ dd. Removing entry § 63.8((c)(1)–(3);
■ ee. Adding entries § 63.8(c)(1)(i), § 63.8(c)(1)(ii) and § 63.8(c)(1)(iii);
■ ff. Revising entry § 63.8 (c)(4)–(8);
■ gg. Revising entry § 63.8(d);
■ hh. Adding entry § 63.8(d)(3);
■ ii. Revising entry § 63.9(b);
■ jj. Removing entry § 63.10(b);
■ kk. Adding entry § 63.10(b)(1);
■ ll. Adding entry § 63.10(b)(2)(i),(ii), (iv), (v);
■ mm. Adding entry § 63.10(b)(2)(iii), (vi) to (xiv);
■ nn. Adding entry § 63.10(b)(3);
■ oo. Adding entry § 63.10(c)(15);
■ pp. Revising entry § 63.10(d)(4)–(5);
■ qq. Revising entry § 63.11(a)–(b);

■ rr. Revising entry § 63.14; and

■ ss. Adding entry § 63.16.

The revisions and additions read as follows:

APPENDIX A TO SUBPART RRR OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART RRR

Citation	Applies to RRR	Comment
* * * * * * *		
§ 63.1(a)(6)	Yes.	
§ 63.1(a)(7)–(9)	No	[Reserved].
§ 63.1(a)(10)–(12)	Yes.	
* * * * * * *		
* * * * * * *		
§ 63.1(c)(3)–(4)	No	[Reserved].
§ 63.1(c)(5)	Yes.	
* * * * * * *		
§ 63.4(a)(1)–(2)	Yes.	
§ 63.4(a)(3)–(5)	No	[Reserved].
* * * * * * *		
§ 63.5(b)(3)–(4)	Yes.	
§ 63.5(b)(5)	No	[Reserved].
§ 63.5(b)(6)	Yes.	
* * * * * * *		
§ 63.6(b)(1)–(5)	Yes	§ 63.1501 specifies dates.
* * * * * * *		
§ 63.6(e)(1)(i)	No	See § 63.1506(a)(5) for general duty requirement. Any other cross reference to § 63.6(3)(1)(i) in any other general provision referenced shall be treated as a cross reference to § 63.1506(a)(5).
§ 63.6(e)(1)–(ii)	No.	
§ 63.6(e)(2)	No	[Reserved].
§ 63.6(e)(3)	No.	
§ 63.6(f)(1)	No.	
§ 63.6(f)(2)	Yes.	
* * * * * * *		
§ 63.6(h)(1)	No.	
§ 63.6(h)(2)	Yes.	
§ 63.6(h)(3)	No	[Reserved].
§ 63.6(h)(4)–(9)	Yes.	
* * * * * * *		
§ 63.7(a)	Yes	Except § 63.1511 establishes dates for initial performance tests.
* * * * * * *		
§ 63.7(e)(1)	No.	
§ 63.7(e)(2)	Yes.	
* * * * * * *		
§ 63.7(g)(1)–(3)	Yes	Except for § 63.7(g)(2), which is reserved.
§ 63.7(h)(1)–(5)	Yes.	
* * * * * * *		
§ 63.8(c)(1)(i)	No	See § 63.1506(a)(5) for general duty requirement.
§ 63.8(c)(1)(ii)	Yes.	
§ 63.8(c)(1)(iii)	No.	
§ 63.8(c)(2)–(8)	Yes.	
§ 63.8(d)(1)–(2)	Yes.	
§ 63.8(d)(3)	Yes, except for last sentence, which refers to an SSM plan. SSM plans are not required.	
* * * * * * *		
§ 63.9(b)(1)–(5)	Yes	Except § 63.9(b)(3) is reserved.
* * * * * * *		
§ 63.10(b)(1)	Yes.	
§ 63.10(b)(2)(i), (ii), (iv), (v)	No.	

APPENDIX A TO SUBPART RRR OF PART 63—GENERAL PROVISIONS APPLICABILITY TO SUBPART RRR—Continued

Citation	Applies to RRR	Comment
§ 63.10(b)(2)(iii), (vi)–(xiv)	Yes	§ 63.1517 includes additional requirements.
§ 63.10(b)(3)	Yes.	
* * *	* *	* *
§ 63.10(c)(15)	No.	
* * *	* *	* *
§ 63.10(d)(4)–(5)	No	See § 63.1516(d).
* * *	* *	* *
§ 63.11(a)–(d)	No	Flares not applicable.
* * *	* *	* *
§ 63.14	Yes.	
* * *	* *	* *
§ 63.16	No.	

[FR Doc. 2015–21031 Filed 9–17–15; 8:45 am]

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Part IV

Federal Communications Commission

47 CFR Parts 1 and 27

Updating Competitive Bidding Rules; Final Rule

FEDERAL COMMUNICATIONS COMMISSION

47 CFR Parts 1 and 27

[GN Docket No. 12–268, WT Docket Nos. 14–170, 05–211, RM–11395; FCC 15–80]

Updating Competitive Bidding Rules

AGENCY: Federal Communications Commission.

ACTION: Final rule.

SUMMARY: In this document, the Commission modernizes and reforms its competitive bidding rules to provide greater flexibility to small businesses and rural service providers and bring greater choices to consumers.

DATES: Effective November 17, 2015, except for §§ 1.2105(a)(2), 1.2105(a)(2)(iii) through (vi), (viii) through (x), and (xii), 1.2105(c)(3) through (4), 1.2110(j), 1.2110(n), 1.2112(b)(1)(iii) through (vi), 1.2112(b)(2)(iii), (v), and (vii) through (viii), 1.2114(a)(1), and 1.9020(e) which contain new or modified information collection requirements that require approval by the Office of Management and Budget (OMB). The Commission will publish a document in the **Federal Register** announcing the effective date of those sections.

FOR FURTHER INFORMATION CONTACT: Wireless Telecommunications Bureau, Auctions and Spectrum Access Division: Leslie Barnes at (202) 418–0660. For further information concerning the Paperwork Reduction Act information collection requirements contained in this document, contact Cathy Williams at (202) 418–2918, or via the Internet at *PRA@fcc.gov*.

SUPPLEMENTARY INFORMATION: This is a summary of the Report and Order; Order on Reconsideration of the First Report and Order; Third Order on Reconsideration of the Second Report and Order; Third Report and Order (*Part 1 Report & Order*), RM–11395, GN Docket No. 12–268, WT Docket Nos. 05–211 and 14–170, FCC 15–80, adopted on July 16, 2015 and released on July 21, 2015. This summary also reflects the Commission's *Erratum,* DA 15–959, released on August 25, 2015, to correct typographical errors in the text of the decision and make ministerial conforming amendments to the rules attached as APPENDIX A to the *Part 1 Report and Order* that correct typographical errors and update cross-references within the part 1 rules and cross-references to those part 1 rules in other service-specific rule parts. The complete text of this document is available for public inspection and copying from 8:00 a.m. to 4:30 p.m. Eastern Time (ET) Monday through Thursday or from 8:00 a.m. to 11:30 a.m. ET on Fridays in the FCC Reference Information Center, 445 12th Street SW., Room CY–A257, Washington, DC 20554. The complete text is available on the Commission's Web site at *http://wireless.fcc.gov,* or by using the search function on the ECFS Web page at *http://www.fcc.gov/cgb/ecfs/.* Alternative formats are available to persons with disabilities by sending an email to *FCC504@fcc.gov* or by calling the Consumer & Governmental Affairs Bureau at (202) 418–0530 (voice), (202) 418–0432 (TTY).

Regulatory Flexibility Analysis

As required by the Regulatory Flexibility Act of 1980, the Commission has prepared a Final Regulatory Flexibility Analysis (FRFA) of the possible significant economic impact on small entities of the policies and rules adopted in this document. The FRFA is set forth in Appendix B of the *Part 1 Report and Order.* The Commission's Consumer and Governmental Affairs Bureau, Reference Information Center, will send a copy of this *Part 1 Report and Order,* including the FRFA, to the Chief Counsel for Advocacy of the Small Business Administration (SBA).

Paperwork Reduction Act

The *Part 1 Report and Order* contains new and modified information collection requirements subject to the Paperwork Reduction Act of 1995 (PRA), Public Law 104–13. They will be submitted to the Office of Management and Budget (OMB) for review under section 3507(d) of the PRA. OMB, the general public, and other Federal agencies will be invited to comment on the new and modified information collection requirements contained in this proceeding.

Congressional Review Act

The Commission will send a copy of this *Part 1 Report and Order* in a report to be sent to Congress and the Government Accountability Office pursuant to the Congressional Review Act (CRA), *see* 5 U.S.C. 801(a)(1)(A).

I. Introduction and Background

1. The *Part 1 Report and Order* modernizes and reforms the Commission's part 1 competitive bidding rules to reflect profound changes in the wireless industry over the last decade. In modernizing the part 1 rules, the Commission provides greater flexibility to smaller companies to build wireless businesses that can spur additional investment in businesses and bring greater choices to consumers. The Commission also provides—for the first time—a bidding credit to eligible rural service providers to help them compete for spectrum licenses more effectively and to provide consumers in rural areas with competitive offerings. Through these changes, and in furtherance of its statutory obligations, the Commission recommits and refocuses its efforts to providing meaningful opportunities to *bona fide* small businesses and rural service providers, including businesses owned by members of minority groups and women (collectively designated entities, or DEs) to participate in auctions and in the provision of spectrum-based services, and in providing such opportunities, to prevent unjust enrichment.

2. The reforms the Commission adopts reflect that the wireless market is vastly different than when its rules were first adopted nearly two decades ago—and since they were last comprehensively revised in 2006. Consumer demand is exploding, data usage is growing exponentially, and faster 4G networks enable ever more data services. Although this kind of growth should naturally lead to greater opportunities for businesses of all sizes and types, small businesses and rural service providers have faced significant challenges to entering the market and competing against larger carriers. The Commission's rules have not kept pace with the dynamic changes in the market.

3. When the DE rules were first adopted, the wireless industry was in its infancy. The rules governing a nascent industry, and even rules adopted ten years ago, could not have envisioned the changes that have occurred in the industry. The wireless market has matured significantly since that time, and today more than 98 percent of mobile subscribers are served by the top four national providers. In recent years, even new large-scale wireless providers, backed by well-capitalized corporations have struggled to develop successful business models to compete in today's wireless marketplace. If major corporations cannot enter the market as new providers and deploy facilities-based services to consumers, it is wholly unrealistic to expect small businesses to do so.

4. Therefore, the rules the Commission adopts provide greater flexibility for small businesses to gain an on-ramp into the wireless industry by leveraging leasing and other spectrum use agreements to gain access to capital and operational experience. The Commission anticipates that, with

experience in operations and investment, smaller companies may ultimately engage in more robust competition, including as facilities-based providers in certain markets, which has been—and remains—a goal of the Commission. Likewise, the Commission expects that a new bidding credit targeted toward eligible rural service providers will both encourage their greater participation in future auctions, and increase their provision of wireless broadband services to unserved and underserved communities, including persistent poverty areas. Ensuring that multiple rural service providers have the ability to compete effectively to acquire spectrum licenses is crucial to promoting consumer choice and competition throughout rural America, as well as to fostering innovation in the marketplace.

5. The Commission undertakes these rule revisions with an understanding that the opportunity to acquire low-band spectrum licenses in the upcoming Broadcast Television Spectrum Incentive Auction (Incentive Auction) will not be replicated in the foreseeable future. The growth in consumer demand for mobile broadband has led to a growing need for spectrum. But not all spectrum is created equal. Low-band spectrum has distinct propagation advantages for network deployment over long distances and is likely to be necessary for existing providers that wish to expand their coverage in rural areas, as well as for new providers that wish to provide service in a rural market. The rule changes the Commission adopts specifically address the difficulties that small businesses and rural service providers confront in today's marketplace, including raising capital to compete in an auction, securing the far greater financial resources necessary to support the construction and operation of a wireless broadband network, and developing a successful business model based on current market structures and consumer needs. The Commission anticipates that these changes will allow *bona fide* small businesses and eligible rural service providers a greater opportunity to participate in spectrum auctions and in the provision of wireless services.

6. At the same time, the Commission adopts common sense reforms that recognize that with increased flexibility comes additional responsibility. The Commission remains mindful of its obligation to ensure that the benefits it provides through DE bidding credits flow only to those intended by Congress. The *Part 1 Report and Order* establishes a cap on the total value of bidding credits that the Commission will award to an eligible applicant in a Commission auction. The Commission also adopts targeted measures to ensure that *bona fide* small businesses and eligible rural service providers are "calling the shots," by limiting the amount of spectrum capacity that a disclosable interest holder in a DE applicant or licensee may use on a license-by-license basis during the unjust enrichment period and by clarifying the types of agreements that will require particularly close scrutiny during its evaluation of DE eligibility. Taken together, and based on experience gained by administering the Commission's auctions program, the Commission believes these measures will ensure that benefits are provided only to eligible DEs. This rulemaking therefore marks another chapter in the Commission's more than twenty-year effort to achieve a proper balance between the parallel goals of affording DEs reasonable flexibility to obtain the necessary resources to participate in auctions and in the wireless industry while also effectively preventing the unjust enrichment of entities that would be ineligible to receive DE benefits in their own right.

7. In the *Part 1 Report and Order,* the Commission also modifies its competitive bidding processes and compliance rules to increase transparency and efficiency, as well as to protect the integrity of the Commission auction process. Chief among these modifications is its prohibition of joint bidding, with limited exceptions, and related changes the Commission makes to its rules regarding multiple applications by commonly controlled entities and prohibited communications. These changes will still afford opportunities for non-nationwide providers and DEs to pool their resources but will update the Commission's rules to promote more robust competition in future auctions and in today's evolving mobile wireless marketplace, especially when anonymous bidding is utilized. The Commission also amends its rules governing former defaulters to simplify the auction process and minimize administrative and implementation costs for bidders. Taken together, the Commission expects that these rule changes will improve the competitive bidding process for all participants.

8. Accordingly, in the *Part 1 Report and Order,* the Commission: (1) modifies its eligibility requirements for small business benefits, and updates the standardized schedule of small business sizes, including the gross revenues thresholds used to determine eligibility; (2) establishes a new bidding credit for eligible rural service providers; (3) implements a cap on the overall amount of bidding credits available for eligible entities in any one auction; (4) strengthens and targets attribution rules to prevent the unjust enrichment of ineligible entities; (5) retains and clarifies DE reporting requirements; (6) revises the former defaulter rule, consistent with the waiver the Commission granted in Auction 97; (7) adopts rules prohibiting joint bidding arrangements with limited exceptions, and makes related updates to its rules on prohibited communications; and (8) adopts rules prohibiting the same individual or entity as well as entities that have controlling interests in common from becoming qualified to bid on the basis of more than one short-form application in a specific auction, with a limited exception for certain rural wireless partnerships and individual members of such partnerships.

II. Eligibility for Bidding Credits

A. Attribution Rules and Small Business Policies

9. *Background.* The Commission revisits its DE eligibility rules in an effort to address the difficulties that small businesses and rural service providers confront in a dynamic, rapidly evolving wireless marketplace. In establishing the Commission's auction authority, Congress vested the Commission with broad discretion to balance a number of competing objectives. Among these are special provisions to ensure that DEs, including small businesses and rural service providers, have the opportunity to participate in competitive bidding and in the provision of spectrum-based services. 47 U.S.C. 309(j)(3)(B), 309(j)(4)(D). For such purposes, Congress granted the Commission the ability to consider the use of bidding preferences. 47 U.S.C. 309(j)(3)–(4). At the same time, the Congress directed the Commission to prevent unjust enrichment as a result of the methods it employs to issue licenses. 47 U.S.C. 309(j)(3)(C), (4)(E). Congress also directed the Commission, through its auction design, to seek to promote several other objectives, including the following: The development and rapid deployment of new technologies, products, and services without administrative delays; economic opportunity and competition through the dissemination of licenses among a wide variety of applicants, including DEs; recovery for the public of a portion of the value of the public spectrum resource made available for commercial use; and efficient and intensive use of

the electromagnetic spectrum. 47 U.S.C. 309(j)(3)(A)–(D). Over the course of the auctions program, the Commission has periodically re-evaluated its rules to strike the right balance among these competing statutory objectives.

10. As the Commission's principal means of fulfilling its statutory objectives for DEs, it offers auction bidding credits to eligible small businesses whose gross revenues, in combination with those of its ''attributable'' interest holders, fall below applicable service-specific size limits. 47 CFR 1.2110. (A bidding credit operates as a percentage discount on the winning bid amount of a qualifying small business. *See 47 CFR 1.2110(f)(1)).* Since 2000, the Commission has applied a ''controlling interest'' standard in all services when making these attribution determinations for small business eligibility. Under this standard, the Commission measures an applicant's size by attributing to it the gross revenues of the applicant, its controlling interests, its affiliates, and the affiliates of the applicant's controlling interests. In 2006, the Commission added a bright-line test to require a small business applicant or licensee to automatically attribute to itself the gross revenues of any entity with which it has an ''attributable material relationship'' (AMR). An applicant or licensee has an AMR when it has one or more agreements with any individual entity for the lease (under either spectrum manager or *de facto* transfer leasing arrangements) or resale (including wholesale arrangements) of, on a cumulative basis, more than 25 percent of the spectrum capacity of any individual license held by the applicant or licensee. 47 CFR 1.2110(b)(3)(iv)(A).

11. Since the adoption of the AMR rule, small businesses have asserted that it impedes their ability to compete successfully in the wireless industry. In the *Part 1 Notice of Proposed Rulemaking* (Part 1 NPRM or NPRM), 79 FR 68172, November 14, 2014, the Commission discussed the significant industry changes that have occurred over the past two decades and in particular during the ten years since it last undertook a major update of the DE eligibility requirements. During this time, the marketplace for mobile wireless services has evolved significantly, both in terms of consumer demand for services and in market structure. According to UBS Investment Research, the total estimated number of wireless customer connections in the United States reached 376.2 million at the end of 1Q 2015, up from 352.5 million at the end of 2014, an increase of 23.7 million connections. The deployment of next generation networks has contributed to an increase of more than 200,000 percent in the number of long-term evolution (LTE) subscribers alone, from approximately 70,000 in 2010 to over 140 million in 2014. Consumers today expect to be able to use mobile wireless services—especially mobile broadband—at home, at work, and while on the go. The marketplace has seen the rapid and widespread adoption of smartphones and tablet computers and an increase in the use of mobile applications, as well as in the deployment of high-speed 3G and 4G technologies, the combination of which has led to more intensive use of mobile networks. For instance, according to providers responding to the most recent CTIA survey, active smartphones topped 208 million in 2014, up 19 percent from 175 million in 2013, and 35.4 million active wireless-enabled tablets and laptops were reported (up 40.5 percent year-over-year) in the same time period. Consequently, mobile data traffic has grown dramatically, increasing from 388 billion MB in 2010 to 4.06 trillion megabytes (MB) at the end of 2014, which represents a greater than ten times increase in the volume of data that was reported just four years ago. Despite technological improvements that have led to more efficient use of existing spectrum and increased investment in infrastructure, this skyrocketing consumer demand for high-speed data has increased providers' need for spectrum at an unprecedented rate.

12. Additionally, the wireless market structure continues to evolve. While the mobile wireless marketplace once consisted of six near-nationwide providers and a substantial number of regional and small providers, over the last ten years there has been consolidation, leaving four nationwide providers and fewer small and regional mobile wireless service providers. More than 98 percent of mobile subscribers are served by the top four providers, which combined serve more than 375 million consumers. This concentration of mobile service providers contributes to the difficulties experienced by small businesses in the wireless marketplace. Moreover, the costs of spectrum and network deployment—especially for small businesses—have increased in the last 20 years. These market realities require DEs to have increased flexibility to gain access to capital in order to acquire licenses and benefit from the different opportunities available to participate in the provision of spectrum-based services. Interested parties therefore urged the Commission to re-examine its rules and policies to provide small businesses with more operational flexibility to enable them to grow their operations and to develop new and innovative products and services. As noted in the *NPRM,* the SBA's Office of Advocacy raised similar concerns.

13. To address these concerns and changing conditions, the Commission sought comment in the *Part 1 NPRM* on whether to eliminate the AMR rule and revisit the policy that has required that small businesses seeking bidding credits to directly provide facilities-based service for the benefit of the public with each of their licenses. The Commission also sought comment on standards for evaluating small business eligibility, and on revising the rules for spectrum manager leasing by DE licensees. During the initial comment cycle, several parties suggested alternate approaches to its proposals, others offered additional suggestions, and some raised questions beyond those covered in the *NPRM.* Accordingly, to assure a more complete record, the Commission released a public notice in April 2015 seeking additional comment on these proposals, suggestions, and questions, as well as on other associated issues.

14. In the *Part 1 Public Notice* (*Part 1 PN*), 80 FR 22690, April 23, 2015, the Commission acknowledged that it had received comments both in favor of and against the Commission's proposed repeal of the AMR rule, and it sought further comment on various methods of modifying its DE eligibility rules. The Commission asked, for example, whether, instead of repealing the AMR rule, the Commission should retain it, in either its existing or a modified form. The Commission sought additional comment on whether it should continue to require DE lessors to provide primarily facilities-based service. The Commission asked whether it should distinguish between types of secondary market arrangements (such as wholesale and resale agreements) entered into by DEs. The Commission sought comment on whether the rules that it applies to secondary market arrangements between DEs and nationwide wireless providers should be different from the ones that it applies to arrangements between DEs and other lessees. The Commission solicited input on whether to have any limit on the amount of spectrum that a DE would be permitted to lease to another DE or a rural carrier. And, among other possibilities, the Commission sought comment on whether it should reconsider a bright-line test for determining who is considered a controlling investor in a DE.

15. Based on the entirety of the record, including the comments filed both in the initial comment cycle and in response to the *Part 1 PN,* the Commission believes that the revised rules it adopts will increase the ability of small businesses to become spectrum licensees. Together, these changes update its eligibility rules to take into account current market realities, namely that DEs need increased flexibility to gain access to capital and, in turn, have greater opportunities to participate in the provision of spectrum-based services. The *Part 1 Report and Order* addresses the specific obstacles these participants face, including raising the capital necessary to compete in an auction; finding sufficient financial resources to support network construction and business operations; and developing a business model based on market needs. It responds to concerns voiced by licensees and potential licensees that the Commission's DE rules have not kept pace with today's environment. And, of equal importance, it updates its rules to ensure that only *bona fide* small businesses qualify for and benefit from the designated entity program. With these rules, the Commission allows small businesses to take advantage of opportunities available under its rules to utilize their spectrum capacity and gain access to capital similar to those afforded to larger licensees.

16. The record demonstrates that, while commenters are divided on the best approach to implement its DE program, they are nonetheless in agreement that it is time for the Commission to recalibrate its rules to achieve an improved statutory balance. The fundamental changes in the market coupled with the evolution of DE participation in the Commission's auctions since 2006, have led it to conclude that it is time to revise its rules and revisit their statutory underpinnings. First, the Commission eliminates the AMR rule. Second, the Commission adopts a two-pronged test to determine eligibility for the award and retention of small business benefits, largely as proposed in the *NPRM.* This test retains the foundation of the controlling interest standard, including the attribution and affiliation requirements of 47 CFR 1.2110, but applies these requirements in a more precise manner, based upon a careful review of all of a DE's relevant relationships and agreements. Under this test, the Commission will apply existing rules requiring attribution of the controlling interests in, and the affiliates of, a small business venture to determine whether the applicant: (1) Meets the applicable small business size standard, and (2) retains control over the spectrum associated with the individual licenses for which it seeks benefits. Pursuant to this more tailored review, eligibility for small business benefits will be determined, as the Commission proposed in the *NPRM,* on a license-by-license basis to ensure that the small business makes independent decisions about its business operations.

17. To better ensure that only eligible entities enjoy the valuable bidding credits that the Commission awards DEs, it adopts an additional attribution requirement under which during the five-year unjust enrichment period, the gross revenues (or the subscribers, in the case of a rural service provider) of a disclosable interest holder in a DE applicant or licensee will become attributable, on a license-by-license basis, for any license acquired with a bidding credit and still subject to unjust enrichment requirements of which the disclosable interest holder uses (or has an agreement to use) more than 25 percent of the spectrum capacity. Lastly, the Commission relies on the language of section 309(j), as opposed to the Commission's prior interpretation of its legislative history, to conclude that there is no statutory requirement for DEs to provide facilities-based service directly to the public with each license they hold. Together, these changes will permit DEs the same flexibility as other licensees under its rules to avail themselves of a wider range of the opportunities to participate in the provision of spectrum-based services. For these same reasons, the Commission modifies the language of 47 CFR 1.9020 as it proposed doing to make clear that DE lessors may fully engage in spectrum manager leasing under the same *de facto* control standard as non-DE lessors.

i. AMR Rule

18. The Commission eliminates the AMR rule, which required a *per se* bright-line attribution of revenues to a DE applicant, even in circumstances where there may have been no control of the DE's overall operations or the DE's spectrum by the spectrum user. Instead, the Commission employs a totality-of-the-circumstances analysis to evaluate an entity's eligibility for, and retention of, small business benefits. Further, the Commission adds a more targeted, license-by-license rule, to ensure that DE benefits do not flow to ineligible entities.

19. Throughout the course of this proceeding, the Commission has received comments that variously advocate keeping, eliminating, or modifying the AMR rule. Many commenters, however, agree with the Commission's proposal to repeal the AMR rule, stating that repeal of the rule will afford small businesses the flexibility needed to obtain the capital necessary to participate in the provision of spectrum-based services. These commenters note that the proposal to adopt a two-pronged standard for evaluating the eligibility for small business benefits relies on well-established Commission standards for evaluating *de jure* and *de facto* control and can be coupled with stronger unjust enrichment provisions to better prevent the abuse of small business benefits. In asking the Commission to eliminate the AMR rule, ARC, for example, indicates that a return to a case-by-case analysis of eligibility using the Commission's control and affiliation standards will align the Commission's policy with marketplace realities. ARC notes that by allowing relationships between DEs and ''large, successful entities, including mobile wireless incumbents,'' DEs will be able to acquire the capital needed to win licenses and ''participate in the provision of spectrum-based services.'' According to ARC, DEs can have such relationships without relinquishing control of their businesses. Similarly, Tristar maintains that the Commission should ''allow DEs to engage in any activities with its licenses that are available to non-DEs, without limit,'' suggesting that a limitation is contrary to the ''plain language'' of section 309(j). CCA also supports eliminating the AMR rule in favor of *de jure* and *de facto* control standards but cautions that repeal of the rule must be accompanied by safeguards to protect against abuse. In addition, USCC argues that setting any absolute limit on the amount of spectrum that a DE may lease or resell will continue to have negative consequences.

20. Other parties oppose the repeal of the AMR rule. T-Mobile argues that doing so will increase the likelihood that DE benefits could flow to ineligible entities or spectrum ''speculators'' in contravention of Congressional intent, and others express similar concerns. Further, some commenters argue that the AMR rule should not only be retained but strengthened. For example, T-Mobile and C Spire advocate that the Commission prohibit a DE from leasing more than 25 percent of its spectrum in the aggregate across one or more licenses. C Spire also argues that, if the AMR rule is retained, a DE should not be allowed to lease more than 25 percent of its total spectrum to any one wireless operator.

21. Although the Commission acknowledges the concerns of parties who urge the Commission to retain or strengthen the AMR rule, the Commission concludes that its collective rule revisions, including the adoption of a more targeted attribution rule that limits the ability of a disclosable interest holder in a DE to use spectrum awarded with a bidding credit decreases the likelihood that DE benefits will flow to ineligible entities in contravention of Congress's intent. Moreover, because the Commission's revised approach utilizes its existing controlling interest and affiliation standards to determine what revenues are attributable to an applicant based upon a rigorous review of all relevant relationships and agreements on a license-by-license basis, the Commission concludes that it no longer needs a bright-line, across-the-board, attribution rule to ensure that a small business makes independent decisions about its business operations. Based on the Commission's auction experience, and in light of the totality of the record in this proceeding, it is persuaded that the AMR rule is overbroad.

22. Eliminating the AMR rule, and replacing it with a more targeted license-by-license attribution rule, will allow small businesses greater flexibility to engage in business ventures that include increased forms of leasing and other spectrum use arrangements, while still having the ability to attract capital investment, even from large providers. DEs, like other licensees, will enjoy greater flexibility to adopt more individualized business models for each license they hold—some that include DE benefits and potentially some that do not. The Commission anticipates that small businesses will, as a result, gain greater access to capital, and in turn, increase their likelihood of participating in auctions and in the provision of spectrum-based services. Under the license-by-license approach for a DE's acquisition and retention of bidding credits that the Commission adopts, a DE will not necessarily lose its eligibility for all current and future small business benefits solely because of a decision associated with any particular license.

23. Although the Commission agrees that its rules must prevent ineligible entities from thwarting the spirit of the DE program and benefitting from bidding credits intended for small businesses, it disagrees that the continuation of the AMR rule achieves that goal. Rather than employing the overly broad attribution standard that has been applied since the adoption of the AMR rule, the Commission concludes that it can balance its competing statutory objectives more effectively and at the same time better empower small businesses to acquire spectrum and operate in today's wireless marketplace. The Commission adopted the AMR rule in 2006 with the goal of preventing unjust enrichment to ineligible entities and ensuring that DEs had opportunities to become independent, facilities-based service providers with each of their licenses. Thus, the AMR rule, in contrast with the other provisions of the Commission's DE eligibility rules, established a bright-line test for triggering the attribution of revenues where a lease was for more than 25 percent of the spectrum capacity of any individual license, regardless of whether the DE retained control of its overall operations or its spectrum. The Commission was concerned about a lessee's ''potential to significantly influence'' the DE applicant. It also noted ''the potential'' for the relationship to impede a DE's ''ability to become a facilities-based provider,'' and sought to avoid a relationship that was ''ripe for abuse.'' The bright-line application of the AMR rule was therefore a tool that the Commission chose to implement in its effort to balance its statutory objectives. Yet commenters in this proceeding have argued that, based on experience, the Commission's current rules, which include the AMR rule, may not be effective in limiting the award of bidding credits to *bona fide* small businesses.

24. The Commission further notes that the adoption of the AMR rule was a departure from its earlier, more comprehensive analysis of how a DE's relationships might lead to attribution of gross revenues, as well as its initial approach to evaluating how much leasing was permissible for DEs at the outset of its secondary market policies. Over the last ten years, industry developments have demonstrated that this regulatory adjustment to prevent unjust enrichment, may have operated to the detriment of the Commission's other equally important statutory objectives, and may not be achieving the goals for which it was adopted. By re-examining the statutory underpinnings of its rules and policies and refining its eligibility rules to reflect current market realities, including the niche roles DEs may play in a mature wireless industry, the Commission can better promote the statutory goal of disseminating licenses among a wide variety of applicants, including small businesses, while also following its competing statutory obligations. Moreover, the revised rules the Commission adopts here refocuses its efforts to thwart speculation by narrowly tailoring the attribution of revenues of those that control the DE's business, control the DE's spectrum, or have an interest in the DE and an agreement to use a spectrum license.

25. Based on the Commission's most recent auction experience, the changes in the wireless marketplace, and the comments and other submissions filed in the record, the Commission agrees with those commenters that contend that the Commission cannot realistically continue to expect DEs to compete successfully at auction or in the marketplace against their larger counterparts while, unlike those competitors, being subject to an across the board, all or nothing rule that limits their ability to make rational, business-based decisions on how best to utilize their licensed spectrum capacity. Absent additional flexibility to gain access to capital through increased secondary market opportunities, on terms similar to their better-financed and more-experienced competitors, it is the Commission's predictive judgment that DEs will not be able to build viable, competitive wireless businesses. The decisions the Commission reaches collectively recognize that permitting DEs to make independent business judgments on how to best provide service—either on their own, directly or indirectly, or in connection with others—will better ensure that DEs themselves are the driving forces of their business operations. Thus, provided that a DE remains fully in control of its primary business and complies with all of the provisions of 47 CFR 1.2110, as amended, the Commission concludes that the degree to which a small business engages in a spectrum use agreement on any particular license need not, without more, presumptively require the bright-line attribution of revenues of the user to the DE in all circumstances.

26. In addition, the Commission relies on the express language of section 309(j) to conclude that there is no statutory requirement for DEs to directly provide facilities-based service to the public with each license they hold. As the Commission noted in the *NPRM,* that policy arose from the Commission's analysis of a part of the legislative history of section 309(j) that explained that anti-trafficking restrictions and unjust enrichment payment obligations were needed to deter ''participation in the licensing process by those who have no intention of offering service to the public.'' As the Commission recognized in the *NPRM,* there are other more narrowly tailored methods that it can

adopt, and do in fact implement, to prevent unjust enrichment and accomplish that same goal. More important, as the Commission also noted in the *NPRM,* ''[i]n interpreting statutes, ''[a]nalysis of the statutory text, aided by established principles of interpretation, controls.'' Section 309(j) does not refer to any requirement of ''offering service to the public,'' much less the provision of facilities-based telecommunications services directly to the public. Nor does it specify what measures the Commission must implement to address unjust enrichment concerns. Rather, it leaves to the Commission the design of auction rules to include those ''as may be necessary.'' Pursuant to the specific language of section 309(j), the Commission has broad discretion to balance many factors.

27. In this regard, the Commission disagrees with the concerns of CAGW and others regarding the retention of the prior policy of direct facilities-based service to the public by licensees that were awarded bidding credits. Specifically, CAGW argues that by ''allowing non-facilities-based entities to qualify for the DE discounts, smaller facilities-based carriers will find it more difficult to obtain the necessary spectrum required to expand their coverage and service.'' To the contrary, the Commission finds that in light of the combined rule modifications it adopted, a singular focus on requiring DEs to provide primarily facilities-based service directly to the public with each and every license they hold is not necessary to prevent unjust enrichment, operates as an impediment to the competing statutory goals, and hinders the ability of small businesses to participate effectively in the provision of spectrum-based services.

28. As the Commission explains, although it eliminates the AMR rule, it emphasizes that it fully preserves its ability to assess whether the terms of any particular spectrum use agreement with a DE, or any other aspect of a relationship between a DE and another party, requires the attribution of that party's gross revenues to the DE generally or on a license-by-license basis under 47 CFR 1.2110, as amended. Contrary to a bright-line application of the AMR rule, this approach should better reflect the nature of the relationship between DEs and the parties with which they are securing financing and/or engaging in spectrum use agreements. The AMR rule was overly broad insofar as it foreclosed DEs from the business flexibility afforded to other licensees and yet was also overly narrow insofar as it did not foreclose other possible misuses of the bidding credits awarded DEs. Accordingly, the Commission revises its rules to determine more precisely what entities have the ability to dictate the DE's business and spectrum use decisions such that their gross revenues should be attributed to the DE applicant for purposes of determining its eligibility for and retention of small business benefits.

29. *Two-Pronged Standard for Evaluating Eligibility for Small Business Benefits.* To assess more accurately an applicant's size for determining eligibility for DE benefits, the Commission adopts a two-pronged standard. Under this test, the Commission will use its existing controlling interest and affiliation rules to determine whether an applicant (or licensee): (1) Meets the applicable small business size standard, and (2) retains control over the spectrum associated with the licenses for which it seeks small business benefits.

30. Under the first prong of the standard, the Commission will apply its existing controlling interest and affiliation rules to determine the gross revenues attributable to a DE. This analysis must determine those that have *de jure* or *de facto* control of, or are affiliated with, the applicant's overall business venture. 47 CFR 1.2110. *De jure* control is typically evidenced by the holding of greater than 50 percent of the voting stock of a corporation or, in the case of a partnership, general partnership interests. 47 CFR 1.2110(c). *De facto* control is assessed on a case-by-case basis to determine whether the licensee has actual control over its business. 47 CFR 1.2110(c). Pursuant to 47 CFR 1.2110, control and affiliation may also arise through, among other things, ownership interests, voting interests, management and other operating agreements, or the terms of any other types of agreements—including spectrum lease agreements—that independently or together create a controlling, or potentially controlling, interest in the DE's business as a whole. *See, e.g.,* 47 CFR 1.2110(c)(5)(vii) through (x). (As discussed below, except under the limited provisions provided for spectrum manager lessors, the decision to discontinue the Commission's policy requiring DE licensees to operate as primarily facilities-based providers of service directly to the public does not alter the rules that require the Commission to consider whether facilities sharing and other agreements confer control of or create affiliation with the applicant). By separating the issue of who controls, or has the potential to control, the DE in regard to its overall business from the inquiry into who uses or controls the license(s) acquired with DE benefits for any particular license, the Commission can more accurately determine the extent to which these benefits are unjustly enriching an ineligible entity. In this way, the Commission can continue to fulfill its statutory objectives by facilitating the ability of small businesses to acquire licenses and participate in the provision of spectrum-based services to the public, while also promoting its competing statutory objectives.

31. This reformed approach received the endorsement of most commenters specifically addressing the two-pronged standard. Under this approach, the Commission will rely on its existing controlling interest and affiliation standards to determine which revenues are attributable to an applicant based upon a careful review of all of its relevant relationships and agreements to ensure that small businesses make independent decisions about their business operations. *See, e.g.,* 47 CFR 1.2110(c)(5)(vii) through (x). (The Commission notes, for example, that standard passive investor protections generally do not give cause for concern but that provisions that limit the DE's use, deployment, operation, or transfer of its spectrum license(s) or business may warrant closer scrutiny). The Commission's existing attribution rules examine the extent to which a small business may combine its efforts, property, money, skill, and knowledge with another party. Further, where there is an agreement to share profits and losses in proportion to each party's contribution to the business operation, the existing rules allow it to consider this in determining whether to attribute the revenues of parties to that agreement to the applicant. The rules the Commission adopts, taken together, will continue to apply a totality-of-the-circumstances approach to allow it to evaluate where an agreement or relationship warrants the attribution of revenues for the purposes of evaluating eligibility. This approach will better enable the Commission to evaluate the various investors in a DE, both controlling and non-controlling, to ensure that a DE remains in command of its business. The Commission emphasizes that this review process will therefore provide it the ability to determine, pursuant to its existing rules, whether an entity with a non-controlling interest in more than one DE has created a relationship of affiliation between applicants for bidding credits such that the revenues of one need to be

attributable to the other. The Commission will also evaluate whether participation of a non-controlling interest holder in more than one applicant renders it an affiliate of both (or multiple) applicants such that the revenues of the non-controlling interest holder (as well as those of its controlling interests, its affiliates, and the affiliates of its controlling interests) should be considered attributable, with respect to either, both, or multiple applicants for purposes of determining eligibility for bidding credits on any particular license or as a general matter. *See, e.g.,* 47 CFR 1.2110(c)(5)(vii)–(x). For instance, where a party has a non-controlling interest in more than one DE applicant or licensee, the Commission will carefully review its investments in, and agreements with, the applicants to evaluate overlapping interests with respect to issues like the use of licensed spectrum capacity, jointly used facilities, shared office space, managerial authority, operational contracts, as well as how the parties may generally be combining their efforts, capital, skill and knowledge. Thus, whether DEs are affiliated with each other or with a common investor, for example, could be informed by the nature of their relationships with that common investor.

32. As in the past, the Commission will carefully review an applicant's claim of eligibility for bidding credits on a case-by-case basis. In so doing, the Commission will examine the facts in the context of both the specific eligibility standards set forth in its rules, and the totality of the circumstances and facts presented by the applicant. While no two cases are the same and each case must be judged on its own facts, the Commission emphasizes that some management, loan, and organizational documents, such as limited liability company agreements, and other types of operational agreements could raise concerns that warrant particular scrutiny as part of its application review. These include agreements and arrangements in which a disclosable interest holder, lender, spectrum lessee, or other interest holder has a role in the day-to-day operations and business of a DE applicant or licensee, as well as provisions that would, taken together or separately, limit the DE's use, deployment, operation, or transfer of its license(s) or business, extending the role of these entities beyond the standard and typical role of a passive investor. While the Commission will look at the totality of the circumstances in each particular case, the Commission also continues to ''emphasize that its concerns are greatly increased when a single entity provides most of the capital and management services and is the beneficiary of the investor protections.''

33. If an entity qualifies as a DE under the first prong, the Commission will evaluate whether it is eligible for benefits on a license-by-license basis under the second prong. Under the second prong, the Commission will evaluate whether a small business is entitled to benefits based on whether it will maintain *de jure* and *de facto* control of the particular license at issue under the terms of any use agreements for each license. For instance, if a DE has a network sharing agreement on a particular license that calls into question whether, under affiliation rules, the user's revenues should be attributed to the DE for that particular license, rather than for its overall business operations, the Commission may conclude that the DE is ineligible to acquire or retain benefits with respect to that particular license. Under this more targeted review, an entity will not necessarily lose its eligibility for all current and future small business benefits, as it did under the application of the AMR rule, solely because of a decision associated with any particular license. Instead, while a small business will lose DE eligibility (and possibly incur unjust enrichment obligations) if it relinquishes *de jure* or *de facto* control of any particular license for which it claimed benefits, the DE could maintain its eligibility for benefits on its other existing and future licenses so long as the DE continues to meet the relevant small business size standard. Thus, an applicant need not be eligible for small business benefits on each of the spectrum licenses it holds in order to demonstrate its overall eligibility for such benefits.

34. As the Commission emphasized in the *NPRM,* under the new standard, small businesses, like all Commission licensees, will remain subject to section 310(d) of the Communications Act, as well as its rules prohibiting unauthorized transfers of control of license authorizations. Accordingly, if a DE executes a spectrum use agreement that does not comply with the Commission's relevant standard of *de facto* control, it will be subject to unjust enrichment obligations for the benefits associated with that particular license, as well as the penalties associated with any violation of section 310(d) of the Communications Act and related regulations. *See* 47 CFR 1.9010 (*de facto* control for spectrum leasing arrangements); *see also Intermountain Microwave,* 12 FCC 2d 559, 559–60 (1963) (*Intermountain Microwave*) (*de facto* control for non-leasing situations); 47 CFR 1.2110(c) (*de facto* control for DEs); *Part 1 Fifth Report and Order,* 65 FR 52323, August 29, 2000 (incorporating the *Intermountain Microwave* principles of control into 47 CFR 1.2110 of the Commission's rules. If that spectrum use agreement (either alone or in combination with the DE controlling interest and attribution rules), goes so far as to confer control of the DE's overall business, the gross revenues of the additional interest holders will be attributed to the DE, which could render the DE ineligible for all current and future small business benefits on all licenses. Except where the leasing standard of *de facto* control applies under 47 CFR 1.9010 and 1.9020 of the secondary market rules, the criteria of *Intermountain Microwave* and *Ellis Thompson* continue to apply to every Commission licensee for purposes of assessing whether it can demonstrate that it retains *de facto* control of its business venture and spectrum license.

35. *Standard for Evaluating DE Leasing.* For the same policy reasons the Commission also adopts its proposal to apply to DE spectrum manager lessors the same *de facto* control standard that it applies to non-DE spectrum manager lessors, and modifies 47 CFR 1.9020 of its rules accordingly.

36. The limited comment the Commission received on this issue was generally supportive of adopting the rule modifications proposed in the *NPRM.* The DE Coalition, USCC, and WISPA all support the proposed modifications of the rules to clarify that DE lessors may fully engage in spectrum leasing under the same *de facto* control standard and to the same extent as non-DE lessors under a spectrum manager lease. WISPA further states that a uniform standard makes the application process for spectrum leases more predictable, eliminates the need for special filings, and reduces administrative burdens. WISPA also maintains that the proposal will enable small businesses to enter into leasing arrangements that are well understood and utilized within the marketplace, and will ensure that small business licensees retain control over certain obligations, preventing any sham arrangements or unjust enrichment for non-small business entities. Blooston Rural, however, argues that, while some relaxation of the leasing restrictions is in order, its *NPRM* proposals will invite abuse of the bidding credit program by allowing the largest carriers to invest in a DE, and then use spectrum leases to gain full access to spectrum obtained with the small business benefits.

37. In order to allow DEs the ability to make independent business judgments about how to best utilize the spectrum capacity of each of their licenses, the Commission revises 47 CFR 1.9020(d)(4) of its rules to remove the conflicting reference to the control standard of 47 CFR 1.2110, as it proposed to do in the *NPRM.* The Commission agrees with WISPA that this modification will enable small businesses to enter into leasing arrangements that are well understood and utilized within the marketplace, and ensure that small business licensees retain sufficient control of their overall operations and regulatory obligations to safeguard the award of bidding credits.

38. Pursuant to this modification, a DE will, like any other spectrum manager lessor, be considered to have *de facto* control over the portion of a spectrum license for which it, as lessor, has a spectrum manager lease provided that it: (1) Maintains an active, ongoing oversight role in ensuring that the lessee complies with Commission rules and policies; (2) retains responsibility for all interactions with the Commission required under the license related to the use of the leased spectrum; and (3) remains primarily and directly accountable to the Commission for any lessee violation of these policies and rules. (A DE's ongoing control over any non-leased portion of a license for which it has benefits is evaluated according to 47 CFR 1.2110 and the criteria set forth in *Intermountain Microwave* and *Ellis Thompson*). The Commission stresses however, that it will not allow spectrum manager leases of licenses subject to DE benefits to automatically go into effect under the Commission's 21-day processing period. Instead, staff will carefully review DEs' requests to engage in spectrum manager leasing, and review such requests as necessary to determine whether the terms of the spectrum management lease agreement include provisions that confer *de jure* or *de facto* control of the DE lessor's business venture. These rule modifications will allow a DE to participate in the secondary market under the same control standard as other wireless licensees.

39. The Commission nonetheless recognizes Blooston Rural's concerns and agrees that in relaxing its rules with respect to leasing generally, the Commission must counterbalance such modifications to ensure that ineligible entities cannot invest in a DE and then use spectrum leases to gain full access to spectrum obtained with the small business benefits. Accordingly, to address the scenario raised by Blooston Rural, the Commission adopts a specific attribution rule that will serve to limit the amount of spectrum capacity a disclosable interest holder in a DE applicant or licensee will be able to utilize during the five-year unjust enrichment period under any use agreement.

ii. Attribution Rules

40. In the *Part 1 PN,* the Commission sought comment on various recommendations from commenters for modifying its attribution rules to better ensure that only *bona fide* small businesses qualify for bidding credits. These recommendations include, among other things, modifications to the applicable attribution, controlling interest or affiliation rule to alter the types of equity arrangements available to a DE applicant by (a) attributing to a DE the revenues and spectrum of any entity holding certain interests of more than ten percent, (b) restricting certain large carriers or companies from providing a certain amount of capital or otherwise exercising control over a DE, and (c) adopting a rebuttable presumption that equity interest of 50 percent or more represents *de facto* control of the DE. The Commission also invited comment on other suggestions by commenters regarding DE eligibility for benefits, such as: (1) Adopting a 25 percent minimum equity requirement for DEs; (2) limiting the total dollar amount of DE benefits that any DE (or group of affiliated DEs) may claim during any given auction, based on particular criteria; (3) limiting the overall amount that a small business can bid based on a revenues or population-based metric; (4) narrowing the scope of the affiliation rules to exclude individuals and entities whose revenues are currently attributable to a DE, such as directors and certain family members; and (5) clarifying the affiliation rules to prevent rural telephone companies from losing DE status because they hold a fractional interest in a cellular partnership if the rural telephone company has no ability to control the partnership's day-to-day operations and/or strategy.

41. After review of the comments submitted in response to its inquiry, the Commission adopts a new attribution rule to establish a limit on how much spectrum capacity a disclosable interest holder in a DE applicant or licensee (which for the purposes of this rule the Commission defines as any party holding ten percent or greater interest of any kind in the DE, including but not limited to, a ten percent or greater interest in any class of stock, warrants, options or debt securities in the applicant or licensee) can use in any particular license awarded with DE benefits, and reject the remaining suggestions.

42. *Limitation on Spectrum Use by a Disclosable Interest Holder in a DE.* To ensure that DE benefits are awarded to only eligible, *bona fide* small businesses, the Commission adopts a new attribution rule that will serve as an additional safeguard to prevent the circumvention of the Commission's rules during the unjust enrichment period for any license awarded with bidding credits. Specifically, the Commission adopts an additional attribution requirement under which, during the five-year unjust enrichment period, the gross revenues (or the subscribers in the case of a rural service provider) of a disclosable interest holder in a DE applicant or licensee will become attributable, on a license-by-license basis, for any license in which the disclosable interest holder uses, in any manner, more than 25 percent of the spectrum capacity of a DE's license awarded with bidding credits.

43. A number of commenters suggested that the Commission restrict larger nationwide and regional carriers, entities with a certain number of end-user customers, and/or other large companies from providing a material portion of the total capitalization of DE applicants or otherwise exercising control over such applicants as part of the definition of material relationship. In responding to its inquiry on this matter, several commenters offer various suggestions on whether and to what extent the Commission should implement such a restriction. Blooston Rural, for instance, supports a restriction on leasing spectrum to nationwide carriers that have invested in the applicant/licensee, along with large regional carriers and other large companies. Tristar argues that some restriction on DE financing arrangements involving other participants and incumbent service providers is merited. In support of a new restriction, AT&T reasons that, given the capital costs for deploying a service, the cost of the licenses should be a small fraction of a DE's operational fund; thus, if a DE has the financial wherewithal to compete in urban markets and fulfill the Commission's performance benchmarks, ''it seems unlikely that the [DE] is the type of business that any rational small business program is meant to assist.'' At the same time, AT&T/Rural Carriers caution that any new restrictions should include an exception for arms-length commercial loans to bidding entities.

44. Other commenters also opine that a restriction should also be imposed on

entities utilizing the rural service provider bidding credit. Among these commenters, Blooston Rural supports the adoption of some restriction that would limit the ability of a DE to lease spectrum that is acquired with the rural service provider bidding credit to an investor, provided that the Commission carve out an exception for an investor that is ''a rural telephone company or rural telco subsidiary/affiliate with wireless or wireline presence in the original license area (as established by its existing ETC designation), or to an independent wireless ETC that is certif[ied] in the original license area and that has fewer than 100,000 subscribers.'' RWA/NTCA agrees with Blooston Rural's restriction, including the exception, but would also apply the restriction to nationwide wireless carriers who are not investors of the DE and impose the restriction for the initial license term.

45. Based on the common theme in commenters' proposals, the Commission incorporates into 47 CFR 1.2110 a new attribution rule under which, during the five-year unjust enrichment period, the gross revenues (or the subscribers in the case of a rural service provider) of a disclosable interest holder in a DE applicant or licensee will become attributable, on a license-by-license basis, for any license in which the disclosable interest holder uses, in any manner, more than 25 percent of the spectrum capacity of a DE's license awarded with bidding credits. For the purposes of this rule, the Commission defines a disclosable interest holder as any party holding a ten percent or greater interest of any kind in the DE, including, but not limited to, a ten percent or greater interest in any class of stock, warrants, options, or debt securities in the applicant or licensee. Despite receiving a number of the alternative proposals from commenters, the Commission declines to specifically restrict financing or agreements with large or regional carriers, because doing so may impede a DE's ability to raise capital and gain operational experience. Instead, the rule the Commission adopts should safeguard the award of valuable bidding credits by carefully targeting the concerns of commenters, which generally seek to ensure ineligible entities don't improperly benefit from DE bidding credits by gaining full unrestricted access to use the spectrum license.

46. For DEs that acquire licenses with the new rural service provider bidding credit, however, the Commission will include an exception to this new attribution rule, similar to that suggested by Blooston Rural, to apply to any disclosable interest holder that would independently qualify for a rural service provider bidding credit. Pursuant to this exception, a rural service provider may have spectrum license use agreements with a disclosable interest holder, without having to attribute the disclosable interest holder's subscribers, so long as (a) the disclosable interest holder is independently eligible for a rural service provider credit and (b) the use agreement is otherwise permissible under its existing rules. This exception should ensure that rural service providers can work in concert to provide service to rural areas.

47. In adopting this new attribution rule, the Commission disagrees with commenters who oppose the adoption of limitations on the ability for an investor to engage in certain transactions with a designated entity concerning licenses acquired with bidding credits. Specifically, Council Tree argues that such restrictions would contravene Congressional intent and impede the ability of DEs to acquire the necessary capital to compete with incumbents who already have a distinct operational advantage in the wireless marketplace. Council Tree also maintains that ''the adoption of any of these [*Part 1 PN*] proposals to restrict the size and impact of DEs in spectrum auctions [serves] the *private* financial interests of the largest, most entrenched incumbents.'' CCA voices concern that the limitations would be too restrictive and create significant disincentives to investment. USCC asserts generally that most of the proposals violate the principles of simplicity and avoiding different classes of licenses—and begs the question of why the Commission does not use *Intermountain Microwave*—as the ultimate test. Moreover, USCC opines that ''when individual, properly constituted DEs win auctions, that is not an abuse of the rules; [r]ather, it carries their intent.''

48. While the Commission recognizes the concerns echoed by various commenters that investor use limitations could restrict the ability for DEs raise capital, the Commission concludes that this carefully targeted rule, applied on a license-by-license basis during the five-year unjust enrichment period, is necessary to fulfill its responsibility of ensuring that DE benefits flow only to those intended by Congress. The Commission therefore adopts this rule to balance the increased flexibility the Commission has granted to DEs to raise capital against its obligation to prevent investors from benefitting from bidding credits indirectly through their use of a DE's discounted license. The rule is also consistent with its two-pronged analysis of small business eligibility, allowing a DE to monetize individual licenses without losing its overall eligibility, while ensuring that the DE remains independent and in control of its business as a whole. Moreover, the Commission disagrees with USCC that such a rule is unnecessary because the application of the criteria in *Intermountain Microwave* sufficiently mitigates the additional risks of unjust enrichment and undue influence that may arise after the elimination of the AMR rule and relaxation of the Commission's facilities-based service requirements. Rather, by establishing this targeted rule to focus only on the intersection of a disclosable interest in a DE and the disclosable interest holder's use of 25 percent or more of the spectrum capacity of a license awarded with DE benefits, the Commission can alleviate commenters' concerns regarding unjust enrichment and, at the same time, provide DEs with more transparency and predictability in the auctions and licensing process.

49. Because the Commission is implementing this 25 percent use limit for disclosable interest holders in a DE, the Commission will not incorporate into its rules any of the alternative attribution restrictions for which it sought comment. For instance, the Commission will not modify its rules to require a DE to attribute the revenues and spectrum of any entity that holds more than a ten percent interest in any type of DE and will instead adopt the more targeted rule, evaluating on a license-by-license basis. Most commenters generally oppose the proposal that would attribute to a DE the revenues and spectrum of any spectrum holding entity that holds an interest, direct or indirect, equity or non-equity of more than ten percent. Some of these commenters assert that the proposal is too restrictive and impedes the ability of a DE to raise capital to compete successfully in spectrum auctions. NTCH further opposes the notion that non-equity debt financing should be considered for determining DE eligibility because it would disadvantage small businesses who must often rely on non-institutional sources of debt financing. The Commission agrees with these commenters, and declines to accept the positions of those like C Spire that support a more restrictive proposal. The Commission also agrees with T-Mobile, which suggests that the ten-percent proposal, while a ''step in the right direction, may be too restrictive.''

Accordingly, the Commission concludes that its more targeted attribution rule achieves the proper balance of its numerous policy goals.

50. Nor will the Commission adopt a rebuttable presumption that equity interests of 50 percent or more represent *de facto* control of a DE, which would run counter to its overall policy goal of providing additional sources of access to capital. The Commission notes that commenters are divided in response to the establishment of a rebuttable presumption that equity interests of 50 percent or more represent *de facto* control of a DE. Some commenters, including Blooston Rural and Tristar, support this proposal, with some changes. Blooston Rural would support the rebuttable presumption, provided that ''properly insulated passive investors'' are not ''lumped together to determine a 50% or greater interest.'' Tristar would also establish a rebuttable presumption that any provider of financial support of 25 percent or more, direct or indirect, should be considered a controlling interest of the DE. T-Mobile argues that this proposal is a compromise position and is consistent with the Commission's existing standards for evaluating *de jure* control. Opponents of the rebuttable presumption argue that such a provision may not withstand judicial scrutiny and would create a ''logistical nightmare'' for small businesses and Commission staff. Additionally, USCC argues that, like the minimum equity requirement, this policy would limit DEs' flexibility to attract financing and undercut the underlying policies of the DE program. The Commission agrees with commenters that this type of restriction would impede a DE's access to capital without any counter-balancing benefits that cannot otherwise be achieved by its new targeted rule. Moreover, for similar reasons the Commission believes that the attribution rule it adopted will address the concerns underpinning this type of proposal in a directed, practical, and effective way.

51. The Commission also rejects the suggestion to adopt a rule that would require a DE to provide, without outside investment, a minimum of 25 percent of the equity of its business, as such a requirement could be unachievable for many small businesses and rural service providers, particularly in capital intensive auctions. For instance, in opposing this suggestion, KSW contends that ''very few entities have 25 percent or more held by a single entity,'' and that ''the result would be less DE funding, and far fewer and much smaller DEs.'' Also rejecting this suggestion, USCC notes that the Commission previously declined to adopt a minimum equity requirement because ''it would subject DEs to unnecessary competitive harms and conflict with the Commission's goal of providing DEs with 'maximum flexibility' in attracting financing.'' CCA, however, reasons that a minimum equity requirement could be reasonable but that the suggested 25 percent requirement is too high. The Commission has historically declined to adopt a minimum equity requirement for the controlling interests of a DE applicant, and it continues to do so here because it concluded it would be counter-productive to its efforts to afford DE applicants greater flexibility to gain access to capital.

52. The Commission notes that each of the proposals it declines to adopt attempts to limit the ability of ineligible entities to circumvent its rules and reap the benefits of DE discounts through their investments in, and business involvements with, DEs. After reviewing the record in this proceeding, and taking into account the Commission's experience in administering the bidding credits program, it concludes that the rule it adopts will best achieve the ends these commenters seek without the associated drawbacks in furtherance of its statutory obligation to balance dual directives.

53. *Implementation of the New Eligibility Test and Attribution Rule.* The Commission will implement its new eligibility test and attribution rule on a prospective basis, including for licenses in the 600 MHz band. Additionally, the Commission will apply this rule prospectively, so as to apply to all determinations of eligibility for designated entity benefits with respect to: Any application filed to participate in auctions in which bidding begins after the effective date of the rules; all applications for a license authorization, assignment, or transfer of control; and any spectrum leases or reports of events affecting a designated entity's ongoing eligibility filed on or after the release date of the *Part 1 Report and Order.* In light of the changes that the Commission is making to its eligibility and attribution rules, it will require additional information from applicants and licensees in order to ensure compliance with the policies and adopted rules. The Commission will therefore modify its FCC forms and the Universal Licensing System (ULS) to implement these new rule changes.

54. *Attribution of Revenues Where the Applicant Holds an Interest in a Cellular General Partnership.* In the *Part 1 PN,* the Commission invited comment on whether it should modify its affiliation rules to prevent an applicant from losing eligibility for small business bidding credits because it holds an interest in a cellular partnership that was established as part of the cellular B Block settlement process that applied to wireline companies in the mid to late 1980s. Commenters have noted that despite being a partner, a rural telephone company typically holds only a fractional ownership interest in these partnerships and thus has no ability to control the partnership's day-to-day operations. Commenters therefore request that the Commission not attribute the revenues of the partnership to such an applicant when it is seeking eligibility for a small business bidding credit.

55. While the Commission understands that some rural telephone companies may not be eligible for a small business bidding credit because they hold an attributable interest in a cellular general partnership, the Commission must make every effort to ensure that its DE benefits inure only *bona fide* eligible entities. Accordingly, the Commission declines to adopt a rule that would exempt an applicant that is a controlling interest, or an affiliate of a cellular partnership, from attributing the revenues of the partnership for the purposes of complying with the size standards for eligibility for small business bidding credits. However, the Commission has adopted a bidding credit for eligible rural service providers based upon the number of subscribers of the applicant (as well as its controlling interests, affiliates and the affiliates of its controlling interest), and for that bidding credit the Commission has created an exception to its attribution rules for existing rural partnerships.

56. *Attribution of Immediate Family Members and of Officers and Directors.* The Commission also declines to adopt changes to two of its other attribution rules. In the *Part 1 PN,* the Commission sought comment on whether it should narrow the scope of two of its attribution requirements where an immediate family member or a particular officer or director is unlikely to exercise control over the applicant. Under the kinship affiliation requirement, immediate family members are rebuttably presumed to ''own or control or have the power to control interests owned or controlled by other immediate family members.'' 47 CFR 1.2110(c)(5)(iii)(B). Under the officer/director attribution requirement, officers and directors of an applicant (or of an entity that controls an applicant or licensee) are considered to have a controlling interest in the applicant (or licensee). 47 CFR 1.2110(c)(2)(ii)(F).

57. Both NTCH and Tristar propose relaxing the kinship affiliation requirement, arguing that the existing rule is too broad and requires attribution of the revenues of family members who are unlikely to have involvement with the applicant. NTCH also contends that the Commission must narrow the officer/director attribution requirement, claiming that it encompasses officers ''who have no executive authority whatsoever.'' Blooston Rural, on the other hand, advises caution before the Commission narrows either rule, noting that officers and directors of privately held companies often have significant control and pointing out that the kinship affiliation presumption is, by its terms, rebuttable.

58. The Commission finds its current rules help ensure that only *bona fide* small businesses receive small business bidding credits. Accordingly, the Commission will leave both rules intact. There is minimal record support for eliminating or modifying these rules, particularly the officer/director attribution requirement. Moreover, the Commission has found the kinship affiliation rule to be effective in forcing the attribution of revenues of close relatives who are likely to exercise control over an applicant. Thus, the rule continues to serve the purpose for which the Commission first adopted it in 1994 for broadband PCS. The Commission explained then that the reason for the rule is twofold, to ensure that entities receiving DE benefits are actually in need of special financial assistance and to prevent otherwise ineligible entities from circumventing the rules by funding family members who purport to be eligible applicants. The Commission further explained that it was adopting bright-line tests for determining when the financial interests of spouses and other family members should be attributed, because, as a practical matter, it would not be able to resolve all questions pertaining to the individual circumstances of particular applicants for an auction before bidding began.

59. At the same time, the Commission acknowledged that a non-spousal family relationship may not carry the same potential for abuse that a relationship between spouses does. Accordingly, while the Commission adopted spousal attribution of revenues as a non-rebuttable standard (unless the spouses are legally separated) (*see* 47 CFR 1.2110(c)(5)(iii)(A)), it implemented the kinship rule as a rebuttable presumption. Now, as then, a winning bidder may rebut the presumption by showing that close family members cannot exercise control over the business, *i.e.,* that ''the family members are estranged, the family ties are remote, or the family members are not closely involved with each other in business matters.'' The Commission therefore concludes that the rule is not overly broad and continues to serve a specific necessary purpose.

60. Likewise, the Commission believes that defining officers and directors as controlling interests of a DE applicant or licensee similarly helps ensure that ''only those entities truly meriting small business status qualify for its small business provisions.'' NTCH argues that the attribution rule discourages individuals from taking seats on an applicant's board of directors, because their ''private revenue information'' would have to be disclosed. Contrary to NTCH's concerns, personal net worth, including personal income, of the officers and directors need not be disclosed. 47 CFR 1.2110(c)(2)(ii)(F). More important, the revenue information of officers and directors need be disclosed only if their company is seeking a substantial public benefit by applying for a bidding credit. Finally, NTCH has provided no specific examples of instances where it thinks that the rule should not have been applied and has therefore not convinced the Commission that changing the rule is in the public interest. The Commission reminds NTCH and all interested parties that if an applicant considers a waiver of the rule to be warranted in its case, it may seek one under 47 CFR 1.925.

61. *Tribal Exclusion from affiliation coverage.* In the *Part 1 PN,* the Commission sought comment on a request that it ''eliminate the preferential treatment for [Alaska Native Corporations (''ANCs'')] that do not meet the standard definition of small business under its attribution rules.'' Under the Commission's small business attribution rules, applicants or licensees affiliated with Indian tribes or ANCs are not required to include revenues of those tribes or ANCs, other than gaming revenues, in their gross revenues for purposes of determining their eligibility for bidding credits. When the Commission adopted this exclusion from the affiliation requirements in 1994, it sought to ensure that its rules remained consistent with other federal laws, policies, and regulations, most notably the affiliation rules of the Small Business Administration (SBA). The Commission asked in the *Part 1 PN* whether it should now eliminate the exclusion, whether the rules concerning Indian tribes or ANCs remain consistent with other federal policies, and whether these rules increase the risk of unjust enrichment. The Commission also asked commenters to tell it whether and how it should amend the rules.

62. The Commission has received no record support for this proposal. Fourteen commenters, all tribes or tribal organizations, oppose elimination of the affiliation exclusion. NCAI emphasizes ''the unique legal relationship that exists between the federal government and Indian Tribal governments, as reflected in the Constitution of the United States, treaties, federal statutes, Executive orders, and numerous court decisions,'' amounting to a fiduciary trust relationship. NCAI also explains that the Commission's preservation of the tribal attribution exclusion is essential because of the economic disparities that exist on tribal lands and the well-documented challenges of deploying communications infrastructure there. Several of the tribal entities explain that they still lack high-speed and dependable telecommunications services and face daunting barriers to obtaining spectrum licenses for the provision of commercial mobile wireless services on tribal lands. Under these circumstances, the commenters tell the Commission, access to capital is crucial. As one commenter asserts, any adverse modification of the affiliation exclusion will effectively nullify the Commission goal that telecommunications services be deployed to tribal communities.

63. Native Public observes that ''[t]he Commission has repeatedly found that Native Americans have had less access to telecommunications services than any other segment of the population[,]'' adding that the Commission's DE tribal policies ''advance the interests of an underserved minority population group, those of the Tribal governments which have a sovereign right to set their own communications policies and goals for the welfare of their members.'' And Nez Perce encourages the Commission to retain its ''well established and rooted policies to bolster a tribe's resources to deploy wireless services on their land to serve the communication needs of their population.'' Other commenters all express similar views.

64. When the Commission decided to include this exclusion under its definition of the term ''affiliate,'' it concluded that the exclusion would ensure that Indian tribes and Alaska Regional or Village Corporations have a meaningful opportunity to participate in spectrum-based services from which they would otherwise be precluded, and that such an exclusion for these specified entities would not entitle them to an unfair advantage over entities that are otherwise eligible for small business

status. The affiliation exclusion for ANCs is based on their ''unique legal constraints'' imposed by statute that are inapplicable to other businesses. These constraints preclude ANCs from ''utilizing two important means of raising capital: (1) The ability to pledge the stock of the company against ordinary borrowings, and (2) the ability to issue new stock or debt securities.'' In addition, land holdings held by Indian tribes cannot be used as collateral for purposes of raising capital, ''because the land holdings are owned in trust by the federal government or are subject to a restraint on alienation in the government's favor.'' The exception was carefully tailored so as not to extend it to gaming revenues, which are not subject to the same constraints. The Commission has also not been presented with any evidence that its rule is no longer consistent with other federal laws, policies, and regulations, most notably the affiliation rules of the SBA such that the Commission should revisit the exclusion. In light of commenters' significant opposition and the absence of a record supporting the elimination or modification of this attribution exclusion, the Commission retains the exclusion in its current form.

B. Bidding Credits

65. In the *NPRM,* the Commission took a fresh look at its bidding credit program to ensure that it remains a viable avenue for DEs to meaningfully participate in auctions and thereby create additional competition and investment in the wireless marketplace. The Commission's bidding credit program was adopted in 1994 and is the primary way it facilitates participation by designated entities in auctions. Section 309(j)(4)(D) of the Act states that the Commission must consider using bidding preferences when prescribing regulations for acquiring service-specific licenses through competitive bidding. A bidding credit provides a percentage discount on winning bids for eligible DEs. The Commission defines bidding credit eligibility requirements for DEs on a service-specific basis, taking into account the capital requirements and other characteristics of each particular service.

66. After reviewing the record, the Commission revises its rules for its bidding credit program. Specifically, the Commission updates its small business eligibility requirements to better reflect the capital-intensive nature of the wireless industry, while retaining its overall three-tiered approach that links the percentage of the small business bidding credit to the size of the business. The Commission also adopts a new bidding credit for eligible rural service providers to increase their participation in auctions and provide greater opportunities for bringing crucial wireless voice and broadband services to rural areas, including underserved and unserved areas and areas of persistent poverty. By adopting this new bidding credit, the Commission facilitates greater access by multiple entities to valuable, low-band spectrum, thereby fulfilling its statutory goals of promoting competition and ensuring the efficient use of spectrum. As a further step to ensure these benefits continue to flow only those intended beneficiaries, the Commission also adopts a reasonable limitation or cap on the total amount of benefits that a small business or rural service provider can receive in any particular auction.

67. The Commission adopts these rule changes specifically for the 600 MHz service, for which licenses will be offered in the Incentive Auction, to provide eligible small businesses and rural service providers with additional tools to compete meaningfully for low-band spectrum and to promote overall competition in auctions and in the wireless marketplace. On a prospective basis, the Commission will determine the award of bidding credits for small businesses and rural service providers on a service-specific basis taking into account the capital requirements and other characteristics of each particular service, as the Commission currently does.

68. The Commission declines to adopt at this time specific bidding preferences for other types of entities, including those that serve unserved/underserved areas or areas with persistent poverty, as well as those that have overcome disadvantages. The Commission expects, however, that such parties should benefit from the changes it makes to its bidding credit program for small businesses and rural service providers. Finally, the Commission declines to consider any modification of the tribal lands bidding credit because the record does not support revisions to its current policies for the award of this benefit.

i. Small Business Bidding Credit

69. *Background.* The Commission's small business bidding credit program consists of a three-tiered schedule of bidding credits corresponding to small business size definitions that are based on an applicant's average annual gross revenues for the preceding three years. Applicants with average gross revenues not exceeding $3 million are potentially eligible for a 35 percent bidding credit; applicants with average gross revenues not exceeding $15 million are potentially eligible for a 25 percent bidding credit; and applicants with average gross revenues not exceeding $40 million are potentially eligible for a 15 percent bidding credit. In order to qualify for a small business bidding credit, an applicant must demonstrate that its average annual gross revenues, in combination with those of its ''attributable'' interest holders, fall below the applicable financial thresholds. The Commission takes into account the capital requirements and other characteristics of a particular service in establishing which small business definitions to apply to a specific service.

70. In the *Part 1 NPRM,* the Commission sought comment on whether its small business bidding credit program continues to align with the operational demands of small businesses that acquire spectrum and build out services in a formidable wireless marketplace. The Commission invited comment on whether to increase the gross revenue thresholds for defining the small business sizes for bidding credits, using the price index for the U.S. Gross Domestic Product (GDP price index) as the standard for measuring the increase of the thresholds. Specifically, the Commission proposed to increase the average annual gross revenues thresholds from $3 million to $4 million for applicants potentially eligible for a 35 percent bidding credit; from $15 million to $20 million for applicants potentially eligible for a 25 percent bidding credit; and from $40 million to $55 million for applicants potentially eligible for a 15 percent bidding credit. The Commission also sought comment on alternative indices, criteria, or methods that may better reflect the development and relevant range of economic activity in the wireless industry.

71. The Commission invited comment on whether to modify the current bidding credit percentages and whether to add additional tiers of bidding credits. The Commission also asked whether the Commission should continue to evaluate the definition of a small business on a service-by-service basis. Moreover, the Commission sought comment on whether any adopted changes to its part 1 rules should be incorporated into the 600 MHz service rules. In addition, the Commission asked whether it should apply its revised Part 1 rules to re-auctioned licenses for existing services. Based on comments received in response to the *Part 1 NPRM,* the Commission sought additional comment in the *Part 1 PN* on

alternative proposals that would increase the gross revenue thresholds based on other standards, increase the small business bidding credit percentages for all or some of the tiers, and decline to make any changes to the small business bidding credit program until the Commission addressed perceived DE eligibility issues stemming from Auction 97.

72. *Discussion.* The Commission adopts its proposal in the *Part 1 NPRM* to increase the gross revenues thresholds that define the three tiers of small business bidding credits and to retain the existing percentage levels of the small business bidding credits. *See Part 1 NPRM,* 79 FR at 68181–82. Consistent with past practice, the Commission will select, on a service-by-service basis, the small business bidding credits and corresponding definitions that will be available for the applicable auction based on the capital requirements of a particular service. For the Incentive Auction, the Commission will continue to utilize the 25 percent and 15 percent bidding credits, but the Commission will apply the increased gross revenue thresholds that it adopts to the small business size definitions for those bidding credits. The Commission expects that these measures will advance its statutory goals by providing small businesses with an opportunity to remain competitive in an evolving wireless marketplace by facilitating participation in auctions and in the provision of spectrum-based services.

73. *Updating the Standardized Schedule of Small Business Sizes.* The Commission retains its existing three-tiered schedule for determining eligibility for bidding credits, but updates the gross revenues thresholds to reflect the capital challenges small business face in the current wireless industry. The Commission has previously found that robust competition depends critically upon the availability of spectrum for provisioning services. Given the ever-increasing competitive nature of the wireless marketplace, several commenters advocate for modifications to its bidding credit program in order to facilitate a higher rate of participation in auctions by small businesses that might otherwise find it difficult to acquire sufficient capital to compete in spectrum auctions. In this regard, many commenters favor increasing the gross revenue thresholds, with some advocating for higher increases than those proposed in the *Part 1 NPRM.* RWA, for instance, supports the Commission's proposal but also urges it to increase the threshold for the lowest tier from $40 million to $100 million. Council Tree and Blooston Rural also favor using annual gross revenues as the basis for defining the small business sizes for bidding credits.

74. The Commission finds that its three-tiered system for providing small business bidding credits, when properly tailored and implemented, serves the underlying policy interests of its bidding credit program. Therefore, the Commission modifies 47 CFR 1.2110(f) to increase the three tiers of gross revenue thresholds defining eligibility for each small business bidding credit to the following: (1) Businesses with average annual gross revenues for the preceding three years not exceeding $4 million would be eligible for a 35 percent bidding credit; (2) Businesses with average annual gross revenues for the preceding three years not exceeding $20 million would be eligible for a 25 percent bidding credit; and (3) Businesses with average annual gross revenues for the preceding three years not exceeding $55 million would be eligible for a 15 percent bidding credit.

75. In considering how much to adjust the gross revenues thresholds in the small business definitions, the Commission proposed to use as a guide the price index for the U.S. Gross Domestic Product (''GDP price index'') published by the U.S. Department of Commerce on a quarterly basis as part of its National Income and Product Accounts. *See generally* BEA, Interactive Data, *http://www.bea.gov/itable.* The Commission adjusted the current gross revenues thresholds with the percentage change in the GDP price index between 1997 and 2013. The Commission determined that the GDP price index increased by 36.4 percent from 1997 to 2013. Based on this 36.4 percent increase, the Commission proposed new gross revenues thresholds that were obtained by multiplying the current thresholds by 1.364 and rounding to the nearest million.

76. Consistent with the Commission's statutory objectives, it finds that increasing the gross revenue thresholds will enhance the ability of small businesses to acquire and retain capital thereby facilitating their ability to compete meaningfully in today's auctions. At the same time, the Commission avoids setting the small business size thresholds at a level that may be over inclusive and result in DE benefits flowing to entities for which such credits are not necessary. In so doing, the Commission agrees with commenters in favor of using the GDP price index as the basis for calculating the increase for each tier defining the small business size for purposes of the bidding credit. As noted in the *Part 1 NPRM,* the currently available wireless industry price indices do not reflect the dramatic shift from a voice-centric to a data-centric wireless industry, along with the tremendous growth of mobile broadband data services. Moreover, the SBA recently used the GDP price index to adjust its receipts-based industry size standards as part of its size standards review.

77. In adopting this methodology for increasing the gross revenue thresholds for defining small business eligibility for bidding credits, the Commission declines to adopt alternative proposals for adjusting the small business size definitions. For example, ARC would adjust the small business size definition to the cost of auctioned spectrum on a MHz per pop basis. CCA opposes ARC's proposal, noting that it would create uncertainty for DEs as the value of spectrum varies by band and market conditions. The Commission agrees with CCA's assessment and further finds that ARC's proposal would be administratively burdensome to implement without providing a meaningful corresponding benefit. Rather, by using the GDP price index, the Commission establishes a simple bright-line standard to improve the efficiency of the auction process, serve the public interest, and avoid additional implementation costs for small businesses.

78. Additionally, the Commission will not disturb its earlier decision declining to adopt SBA's employee-based business size standard for adjusting its small business size definitions. Council Tree states that the SBA's standard is too inclusive for purposes of establishing DE eligibility. However, CCA promotes the use of SBA's employee-based standard because ''expanding eligibility, rather than shrinking it, may be warranted given the increasing disparity between the largest carriers . . . and all other carriers.'' As noted in the *Part 1 NPRM,* the Commission previously concluded that by adopting the SBA's standard, the Commission would allow many large carriers to take advantage of DE benefits not intended for them. *See Part 1 NPRM,* 71 FR at 68182. Additionally, the Commission notes that there is no data in the record to support reconsideration of its previous conclusion. The Commission will therefore rely on the GDP price index for establishing the small business size definitions to reflect the increased operational costs for small businesses and the need to foster competition in spectrum auctions and in the wireless marketplace.

79. The Commission also declines to adopt proposals favoring a single bidding credit in lieu of the current three-tiered system. AT&T/Rural Carriers, for instance, advocate for the creation of a new 25 percent single bidding credit for small businesses with average gross revenues of less than $55 million. AT&T also notes that this proposal would fulfill the DE program's original vision and safeguard against gamesmanship. Opponents of the single bidding credit argue that the proposal is too limiting and is inconsistent with the Commission's statutory mandates. The Commission finds that AT&T/Rural Carriers' proposal ignores the various sizes and types of small businesses that participate in Commission auctions. Because not all small businesses are alike in the wireless marketplace, the Commission adopted its three-tiered bidding credit system in 1997 so that as a small business grew, it would receive reduced benefits from its DE program. In doing so, its graduated approach allows for other new small businesses to gain a foothold in the marketplace using additional DE benefits. The Commission finds that this approach continues to be relevant and complements its policy for defining bidding credits on a service-by-service basis in order to tailor small business bidding preferences to the capital requirements of a particular service. Thus, the Commission refrains from disturbing its long-standing policy.

80. With respect to the percentage levels of the small business bidding credits, the Commission declines to increase any of the current percentages as proposed by some commenters. These commenters, including ARC, WISPA, KSW, and the DE Coalition, assert that it should increase the bidding credit percentages across all or specific tiers. ARC, for instance, would increase the percentages of all three bidding credit tiers, from the largest to the smallest tier, to 25 percent, 35 percent, and 40 percent respectively. WISPA recommends adjusting the maximum bidding credit up to 45 percent and increasing the other tiers proportionately. Moreover, KSW seeks to change the bidding credit percentages to 40 percent for applicants below the $15 million threshold and 25 percent for applicants below the $40 million threshold.

81. The Commission believes that its decision to eliminate the AMR rule and to increase the gross revenues thresholds for its small business size definitions will sufficiently enhance the benefits of the DE program by helping small businesses obtain access to capital and thereby increase participation and competition in auctions. The Commission is, however, concerned about expanding the scope of DE benefits to a level that may incentivize gamesmanship of the program in the current wireless marketplace. Rather, in light of all the other changes the Commission is making to its rules, it will proceed with care, so that it may assess the impact of its changes to the rules. In this regard, the Commission will revisit these rules as may be necessary in light of its future auction experience. In declining to adopt those proposals to increase the bidding credit percentages, the Commission concludes that the use of the small business size standards and credits set forth in its updated part 1 schedule, when coupled with its other changes, align with its statutory objectives. They also provide a simple, consistent, and predictable avenue for facilitating small business participation in auctions and in today's wireless marketplace.

82. The Commission also declines to adopt PK's proposal for a new entrant bidding credit. Under PK's suggested policy, a new entrant bidding credit would be explicitly designed to attract ''new and innovative technologies,'' noting that ''nothing in the [Act] precludes the use of bidding credits to large businesses to achieve [the Commission's] statutory goals.'' Thus, PK's proposal could provide a bidding preference to well-financed entities that would not otherwise qualify for a bidding credit under its adopted small business size definitions. Tristar submits that well-financed new entrants, among others, should be entitled to some benefits in the upcoming Incentive Auction, but not the same benefits that are available to DEs. CCA opposes this proposal, arguing that ''[it] would be complicated to administer and could lead to unintended consequences and possible gaming.'' The Rural-26 Coalition submits that large, well-financed companies, like an Apple or a Google, ''do not need a helping hand from the American taxpayer'' to be competitive in spectrum auctions. The Commission agrees with commenters that the proposal would conflict with its principles against the unjust enrichment of ineligible entities. Deciding the eligibility criteria for a new entrant would also be difficult to administer and may undercut the underlying policies of the DE program by exacerbating the challenges current DEs face to compete meaningfully in spectrum auctions. The Commission also notes that PK did not offer any details regarding how such a proposal could be implemented. Although the Commission declines to adopt PK's proposal it expects that its new rules for the small business bidding credit program will also help new entrants face the capital challenges of entering the wireless marketplace, provided that they meet the eligibility standards for the bidding credit.

83. Finally, the revisions the Commission has made to modernize and improve its part 1 competitive bidding rules generally respond to the calls by commenters urging it to avoid implementing any bidding credit increases until there is surety that ineligible entities will not benefit from its bidding credit program. The Commission anticipates that the collective rule changes it has made will provide such safeguards. The Commission therefore concludes that the time is ripe to update its standardized Part 1 bidding credit schedule prior to the Incentive Auction. The Commission's actions reflect the current nature of the wireless marketplace and renews its commitment to providing DEs with the opportunity to participate meaningfully in Commission auctions. Further, the Commission adopts targeted measures to ensure that valuable bidding credits are available only to those Congress intended.

84. *Implementation of the Revised Standardized Schedule of Small Business Sizes.* The Commission's rule changes to the Part 1 schedule for small business bidding credits will be available to any particular auction prospectively, including for 600 MHz licenses in the Incentive Auction. *See Incentive Auction Report and Order (Incentive Auction R&O),* 79 FR 48441, 48504–06, August 15, 2014. Specifically, these rules changes will apply to all Commission auctions in which the short-form deadline falls on or after the release date of the *Part 1 Report and Order.* Moreover, applicants claiming any small business bidding credits will continue to be subject to the Commission's DE rules under 47 CFR 1.2110, as amended herein.

85. NTCH supports the incorporation of its rule changes to the Incentive Auction, with Council Tree and WISPA arguing for the adoption of a 35 percent bidding credit (the lowest tier) for the Incentive Auction as well. The Commission declines to reconsider its previous decision in the *Incentive Auction R&O* not to adopt a 35 percent bidding credit for the Incentive Auction. Because of the similarities between the 600 MHz and 700 MHz bands, in the Incentive Auction proceeding, the Commission determined that licensees utilizing the 600 MHz band may face

challenges similar to licensees utilizing the 700 MHz, including issues and costs related to developing markets, technologies, and services. In light of the similar characteristics and capital requirements for both services, the Commission affirms its prior conclusion that it is appropriate to offer the same two bidding credit percentages in the Incentive Auction proceeding as in the 700 MHz auction. Additionally, by increasing the gross revenue thresholds for this schedule, entities that previously exceeded the legacy thresholds may now fall within the new thresholds, and thus become eligible for small business bidding credits. Similarly, the Commission notes that bidders that previously exceeded the legacy thresholds as a result of the AMR rule may now be eligible for a bidding credit under the current thresholds. By adopting its revised three-tiered schedule, the Commission aims to better reflect the potential capitalization costs for new entrants and small businesses in the wireless marketplace and encourage a greater level of participation and competition by small businesses in an auction that offers a significant opportunity for interested applicants to acquire licenses for below-1–GHz spectrum.

86. Consistent with the Commission's current practices it will continue evaluating the definition of small business on a service-by-service basis, determined by the associated characteristics and capital requirements of each service. *See* 47 CFR 1.2110(c)(1). Thus, the Commission will resolve, on a service-by-service basis, the DEs eligible for bidding credits, the licenses for which bidding credits are available, the amount of the bidding credits, and other procedures. Moreover, the Commission will apply the small business size definitions and associated bidding credits to any spectrum licenses in that service assigned through subsequent auctions, absent further action by the Commission. The Commission did not receive any comments squarely addressing these matters, except that WISPA would apply all three tiers of bidding credits to every spectrum auction, including the Incentive Auction. However, WISPA fails to provide data detailing the benefit of a blanket application of the rule in comparison to using a tailored, service-by-service approach. The Commission concludes that a service-specific proceeding is the appropriate avenue for evaluating the capital costs and technical challenges associated with the deployment of a service which will, in turn, drive the selection of the appropriate small business size definition and bidding credit. In taking a service-by-service approach, the Commission will better serve the public interest by promoting the rapid deployment of wireless services. The Commission also intends to review its small business definitions on a more regular basis in the future to ensure that the DE program continues to align with the strategic and operational demands of small businesses in the wireless marketplace.

ii. Rural Service Provider Bidding Credit

87. Background. Under section 309(j), Congress mandated that the Commission design auctions to ''include safeguards to protect the public interest in the use of the spectrum,'' including the objectives to disseminate licenses ''among a wide variety of applicants,'' including rural telephone companies, and to promote the deployment of new technologies, products, and services to ''those residing in rural areas.'' Section 309(j)(4) also directs the Commission to ''ensure'' that various entities—again, specifically including rural telephone companies—''are given the opportunity to participate in the provision of spectrum-based services.'' To this end, it requires the Commission to ''consider the use of . . . bidding preferences'' and other procedures. Historically, the Commission has concluded that section 309(j)(4)(D) does not warrant adoption of an independent bidding credit for rural telephone companies because such entities had not demonstrated that they had experienced significant barriers to raising capital, particularly when compared to other DEs, like small businesses. In the *Incentive Auction R&O,* the Commission found that the record in that proceeding did not provide a sufficient basis to revisit those prior determinations nor sufficient support for adoption of a rural bidding credit.

88. The Commission recognized in the *Part 1 NPRM* that the marketplace for wireless services has evolved significantly since it last comprehensively updated its DE eligibility rules in 2006. Based on this industry-wide evolution, the *Part 1 NPRM* asked commenters to provide data demonstrating whether rural telephone companies lack access to capital or face barriers to formation similar to those faced by other DEs. In response to the *Part 1 NPRM,* several commenters highlighted the fact that rural service providers had difficulty obtaining licenses in Auction 97 and urged the Commission to adopt a bidding credit for rural telephone companies for future auctions. The *Part 1 PN* then sought comment on a number of issues related to whether it should establish a bidding credit for rural telephone companies, including whether a bidding credit would better enable rural telephone companies to compete more successfully at auction. Subsequently, in response to the *Part 1 PN,* AT&T/Rural Carriers submitted a joint proposal that urged adoption of a rural service provider bidding credit. Other stakeholders also offered alternative suggestions for structuring the credit.

89. *Discussion.* The Commission adopts a 15 percent bidding credit for eligible rural service providers that provide commercial communications services to a customer base of fewer than 250,000 combined wireless, wireline, broadband, and cable subscribers and serve primarily rural areas. The Commission agrees with commenters that a targeted bidding credit will better enable rural service providers to compete for spectrum licenses at auction, thereby speeding the availability of wireless voice and broadband services in rural areas. Based on the record established in this proceeding, the Commission anticipates that providing eligible rural service providers with a meaningful opportunity to compete for spectrum licenses will be particularly important in the upcoming Incentive Auction, which will offer multiple blocks of licenses for low-band spectrum. The Commission's action is thereby consistent with other efforts it took in the *Incentive Auction R&O* to facilitate competition in rural areas. The Commission will only permit an eligible small and rural entity to claim one bidding credit though, rather than benefit from both a small business and a rural service provider bidding credit. The Commission believes that the rural service provider bidding credit it adopts will allow a diversity of service providers to compete more effectively for spectrum licenses in rural areas, in furtherance of statutory objectives, while also preventing unjust enrichment of ineligible entities.

90. The Commission's decision today incorporates many of the suggestions offered by commenters, though it declines to adopt in full any single proposal offered by stakeholders for establishing a rural service provider bidding credit. For instance, the AT&T/Rural Carriers Joint Proposal recommended that in order to be eligible for the credit, an applicant must be in the business of providing commercial communications services to a customer base of fewer than 250,000 combined wireless and wireline

customers. Under their particular proposal, however, eligible auction applicants would be permitted to claim a credit of 25 percent, but the credit would be capped at $10 million per bidding entity. Other commenters support the adoption of a rural bidding credit, but under different terms. For example, RWA/NTCA jointly propose a ''Rural Telco Bidding Credit'' of 25 percent that is capped at $10 million and is ''available only to rural telephone companies (or their affiliates/subsidiaries) that seek spectrum in an area in which they are designated as an eligible telecommunications carrier.'' Under the RWA/NTCA proposal, the bidding credit would be separate from, and in addition to, any small business bidding credit for which an applicant would qualify. The Commission notes that this proposal is also supported by other rural stakeholders, such as the Blooston Rural Carriers and the Rural Carrier Coalition. Cerberus proposes a 35 percent bidding credit for rural telephone companies, in addition to any small business bidding credit for which an applicant would qualify.

91. Council Tree, however, claims that rural telephone companies do not have ''the same access to capital issues as other DEs, especially New Entrant DEs.'' Accordingly, Council Tree urges that the Commission not ''elevate'' rural providers ''to a special class of DEs superior to any other DE class.'' CCA ''does not support proposals for the establishment of a separate rural telephone company bidding credit,'' because of ''administrative complexity.'' Accordingly, it urges the Commission to keep a ''simple and straightforward approach of maintaining small business as the touchstone of any bidding credit mechanism.''

92. *The Need for a Rural Service Provider Bidding Credit.* Based upon the record established in this proceeding and its experience garnered over the history of the auctions program, including Auction 97, the Commission now concludes that creating a 15 percent rural service provider bidding credit will better enable eligible rural service providers to compete for spectrum licenses at auction and speed the availability of wireless voice and broadband services to rural areas, consistent with its statutory objectives. *See* 47 U.S.C. 309(j)(3)(A)–(B). In the past, the Commission has noted that due to certain traditional financing programs, rural providers ''may have greater ability than other designated entities to attract capital.'' While the Commission does not believe that rural service providers warrant as great a bidding credit as other DEs, several factors demonstrate that they face obstacles to wireless deployment that are more challenging in their service areas. First, the evidence confirms these difficulties, which are reflected in their inability to provide service that competes with larger providers in rural areas. *See* 17th Mobile Wireless Competition Report, 29 FCC Rcd at 15334 para. 48, 15335 para. 51. Second, the Commission observes that the wireless industry has undergone significant consolidation during the past decade and that concentration in the market share of the major providers has also increased during that time period. Additionally, many rural service providers, although relatively small, are not eligible for small business bidding credits under its size standards to assist them in competing against larger carriers at auction. The record also demonstrates that rural service providers have encountered challenges in their efforts to obtain financing because the rural areas they seek to serve are not as profitable as more densely-populated markets. In a recent NTCA survey, for example, sixty-two percent of survey respondents characterize the process of obtaining financing for wireless projects as ''somewhat difficult'' or ''very difficult,'' and roughly half reported that their ability to obtain spectrum at auction was a concern.

93. Furthermore, commenters have argued that the challenges that rural service providers face in competing for spectrum were reflected in the results of Auction 97, which postdated the Commission's review of this question in the *Incentive Auction R&O.* In Auction 97, 38 qualified bidders were rural telephone companies, or rural telephone company affiliates, and only 28.9 percent of those entities won licenses. Contrary to Council Tree's assertion that the reason many rural telephone companies were unsuccessful in Auction 97 was due to their reduced interest in spectrum and unwillingness to bid competitively in the auction, rural service providers have asserted that they did not bid more aggressively in the auction because many were unable to qualify as DEs under its rules and thus competed against DEs and well-funded national carriers without the benefit of bidding credits.

94. Based on the Commission's review of the record, along with the results of Auction 97, it concludes that a rural service provider bidding credit may have assisted such entities to acquire spectrum suitable for mobile broadband services had a bidding credit been available. Rural service provider commenters have provided evidence illustrating recent increased challenges in securing traditional financing which has resulted in difficulties in competing successfully in auctions. In view of the record and the Commission's experience in running its competitive bidding program, it is convinced that a bidding credit for eligible rural service providers is warranted to ensure that designated entities of all types have the opportunity to acquire spectrum and participate in spectrum based services. The Commission therefore adopts a rural service provider credit for the first time.

95. Under the rules the Commission adopts today, rural service providers will be able to demonstrate eligibility for a 15 percent bidding credit if they serve fewer than 250,000 subscribers and serve predominantly rural areas. The Commission declines to adopt a specific threshold for the proportion of an applicant's customers who are located in rural areas, but puts prospective applicants on notice that it is the Commission's intent that in order for an applicant to be eligible for a rural service provider bidding credit, the primary focus of its business activity must be the provision of services to rural areas. Accordingly, this rule change will provide an incentive for rural service providers to participate more vigorously in upcoming spectrum auctions, including the Incentive Auction. Further, as the Rural-26 Coalition notes, the Commission anticipates that ''more rural companies, including Rural-26 members, likely will participate in the upcoming Incentive Auction than participated in Auction 97, given the favorable propagation characteristics of the 600 MHz spectrum and the opportunity for rural providers to use this spectrum to provide mobile and fixed wireless broadband services in rural markets.''

96. This bidding credit is particularly important in advance of the Incentive Auction, a once-in-a-generation opportunity for small and rural providers to gain access to below-1–GHz spectrum. Spectrum below 1 GHz, referred to as ''low-band'' spectrum, has distinct propagation advantages for network deployment over long distances and is therefore particularly well-suited for deployment in rural areas. Today, two nationwide carriers control the vast majority of this low-band spectrum. Given the limited supply of this spectrum, the continued concentration of low-band spectrum will have a pronounced effect on competition and consumers in rural areas. Indeed, currently, 92 percent of non-rural consumers, but only 37 percent of rural consumers, are covered by at least four

3G or 4G mobile wireless providers' networks.

97. The Commission's adoption of the rural service provider bidding credit is consistent with many of the actions the Commission took in the *Incentive Auction R&O* that were designed to facilitate competition in rural areas. For example, the *Incentive Auction R&O* reserved a modest amount of low-band spectrum in each market for providers that lack low-band capacity. It also adopted Partial Economic Areas (PEAs) to encourage entry by providers that contemplate offering wireless broadband service on a more localized basis. The Commission concluded in the *Incentive Auction R&O* that licensing on a PEA basis is consistent with the requirements of section 309(j) because it will promote spectrum opportunities for carriers of different sizes, including small businesses and rural telephone companies. Finally, the Commission required handset interoperability to ''promote rapid deployment of the 600 MHz band, particularly in rural areas.'' These policy decisions reflect its commitment to address the challenges that rural providers face in competing for spectrum and ensure that consumers in rural areas have access to wireless voice and broadband services. The bidding credit the Commission adopts will build on these policies and support its statutory objectives to disseminate licenses among a wide variety of applicants, ensure that rural telephone companies have an opportunity to participate in the provision of spectrum-based services, and promote the availability of innovative services to rural America.

98. The Commission does not adopt Blooston Rural's proposal to permit a winning bidder to deduct from its auction purchase price the pro rata value of any area partitioned to a rural telephone company, where the area includes all or a portion of the rural telephone company's service area. Under this proposal, the larger carrier ''would be compensated twice for making spectrum available in rural areas—a discount on its final auction payment, plus whatever payment it negotiates with the rural carrier.'' ARC supports this proposal and argues that the rule would ''benefit DEs by providing incentives for partitioning and promote secondary market transactions, which further the prospect of rural telcos obtaining licenses for rural and other underserved/unserved areas where they have an excellent service record.'' The Commission finds that the Blooston Rural proposal would be overly burdensome and challenging to implement. Not only would it require the Commission to review post-auction transactions to determine how much of a discount to apply, but it would also require it to modify its short-form applications to accommodate larger carriers' that intend to receive bidding credits for areas that they partition to rural service providers. Moreover, the Commission notes that it would provide a benefit to carriers for choosing *not* to serve rural areas, which is inconsistent with its goals. Notably, the Commission did not receive any feedback from larger carriers on Blooston Rural's proposal, thus it appears that larger carriers lack interest in participating in such a complex undertaking. While CCA was generally supportive of this proposal in its response to the *Part 1 NPRM,* it reverses course in its response to the *Part 1 PN* and states that ''the nuances of determining which areas should qualify for such credits would introduce undue complexity into already-complex auction processes.''

99. *Eligibility for a Rural Service Provider Bidding Credit.* For purposes of the Commission's rules, as amended, it defines designated entities to include eligible rural service providers. To be eligible for a rural service provider bidding credit, an applicant must be in the business of providing commercial communications services to a customer base of fewer than 250,000 combined wireless, wireline, broadband, and cable subscribers and must also serve predominantly rural areas. A provider may count any subscriber as a single subscriber even if that subscriber receives more than once service. That is, a subscriber receiving both wireline telephone service and broadband would be counted only as a single subscriber. The Commission notes that there is broad consensus in the record to support a benchmark of fewer than 250,000 combined subscribers, which should encompass carriers that provide a variety of services to rural areas, while excluding larger entities that do not have the same demonstrated need for a bidding credit. Moreover, by establishing the eligibility threshold for a rural service provider bidding credit as those with fewer than 250,000 subscribers, rather than 100,000 access lines or less, the Commission selected a criterion that is large enough to permit rural service providers to seek spectrum licenses at auction, expand their coverage areas, grow their subscriber base, and continue to be eligible for bidding credits in future spectrum auctions. Based on the record in this proceeding, the Commission finds that a benchmark of fewer than 250,000 combined subscribers will best ensure that only smaller rural service providers that serve predominantly rural areas receive the bidding credit.

100. To determine whether a provider has fewer than 250,000 subscribers, the Commission will follow an approach similar to how it attributes revenues in the small business bidding credit context, and will determine eligibility by attributing the subscribers of the applicant, its controlling interests, its affiliates, and the affiliates of its controlling interests. *See* 47 CFR 1.2110(f)(2)(i)(4)(C), as adopted herein. As with the Commission's existing small business bidding credits, it anticipates that this approach for establishing eligibility will ensure that applicants are *bona fide* in nature and that a rural service provider credit is only awarded to a designated entity, as Congress intended. Thus, like small businesses, affiliates of rural service provider applicants include entities or individuals that directly or indirectly control or have the power to control the applicant, directly or indirectly are controlled by a third party that also controls the applicant, or have an ''identity of interest'' with the applicant.'' Likewise, controlling interests include those that have *de jure* or *de facto* control of the applicant.

101. Blooston Rural, RWA, and NTCA argue that the Commission should not aggregate the subscribers attributed to an applicant seeking a rural service provider bidding credit in the same manner as it aggregates the gross revenues of a small business seeking a sized-based bidding credit. Instead, they contend that it should award a rural service provider bidding credit when the applicant, and its controlling interests and affiliates each independently demonstrate eligibility for the credit. The Commission disagrees, and concludes that rather than creating greater parity among designated entities, adopting such a method to determine eligibility for a rural service provider bidding credit would undercut its existing small business bidding credit program. In sum, the approach recommended by commenters would permit an applicant that far exceeds the size standard the Commission has established to be an eligible rural service provider, potentially in exponential amounts, to obtain and control spectrum licenses awarded with a bidding credit. Such an applicant would also likely have access to the financial resources of its controlling interests and affiliates and thus granting it a 15 percent bidding credit would be inequitable and contrary to its policy of providing a bidding credit to those designated

entities that have difficulty in obtaining access to capital. Accordingly, the Commission denies this request.

102. The Commission's rules provide options for several parties to combine resources and participate in an auction. Like small businesses seeking eligibility for bidding credits, the Commission will allow rural service providers to form a consortium for this purpose. Under the rules for a rural service provider consortium, the Commission will not aggregate the subscribers of each of the members of the consortium, but will instead determine the eligibility of each individual member for the bidding credit. If the consortium wins a license at auction, either an individual member of the consortium or a new legal entity comprising of two or more individual consortium members may apply for the license(s). Moreover, contrary to the concerns of commenters the Commission is not limiting rural service providers to bidding through a consortium model and stresses that applicants seeking a rural service provider bidding credit have many options to structure their businesses in a manner that complies with its eligibility rules.

103. The Commission also recognizes the concerns of commenters that attributing subscribers of rural service providers in the same manner as it does for the revenues of small businesses will unfairly disadvantage existing rural partnerships, including those that were structured under cellular settlements with numerous controlling interests, yet as a policy matter, still warrant a bidding credit to create greater parity among designated entities. Accordingly, in order not to penalize rural partnerships that were formed for purposes having nothing to do with participation in competitive bidding and to promote more fully the increased participation of rural service providers generally in upcoming auctions, the Commission adopts an exception to its attribution rules for existing rural partnerships. Specifically, for rural partnerships providing service as of the date of the adoption of this decision, the Commission will determine eligibility for the 15 percent rural service provider bidding credit by evaluating whether the members of the rural wireless partnership each individually have fewer than 250,000 subscribers, and for those types of rural partnerships, the subscribers will not be aggregated. Thus we would essentially evaluate eligibility for an existing rural wireless partnership on the same basis as we would for an applicant applying for a bidding credit as a rural service provider consortium. *See* 47 CFR 1.2110(b)(3)(i). This exception will permit eligible rural service providers to receive the benefit of a bidding credit without having to interrupt their existing business relationships or the provision of service to consumers.

104. Notably, because each member of the rural partnership must individually qualify for the bidding credit, by definition a partnership that includes a nationwide provider as a member will not be eligible for the benefit. Similar to attribution in the small business revenue context, the Commission stresses that applicants, including rural wireless partnerships, that do not have an identifiable controlling interest will have all of the subscribers of all of their interest holders evaluated for the purposes of determining eligibility for the bidding credit. The Commission does clarify, as commenters request, that members of such partnerships may also apply as individual applicants or as members of a consortium to the extent it is otherwise permissible to do so under the rules as amended in this decision, and seek eligibility for a rural service provider bidding credit.

105. In regard to the definition of ''rural area,'' while the Communications Act does not include a statutory definition of what constitutes a rural area, the Commission has used a ''baseline'' definition of rural as a county with a population density of 100 persons or fewer per square mile. Facilitating the Provision of Spectrum-Based Services to Rural Areas and Promoting Opportunities for Rural Telephone Companies To Provide Spectrum-Based Services, *Report and Order,* 69 FR 75144, 75146, December 15, 2004. The Commission will use this same definition for purposes of determining whether a carrier serves predominantly rural areas. To qualify for a rural service provider bidding credit, an applicant must certify in its short-form application that it serves predominantly rural areas.

106. Several commenters argue that the Commission should limit the rural service provider bidding credit's eligibility to geographic licenses where the applicant, or one of its members, or affiliates, has Eligible Telecommunications Carrier (ETC) status to provide wireline service. Blooston Rural argues that ''ETC status is an objective and easily-verifiable criterion for determining those geographic markets where the bidder or one of its members has 'presence,' while at the same time preventing the credit from being used to reduce bid price for large urban PEAs.'' The Commission finds that limiting a rural service provider bidding credit to an area where the provider has been certified for ETC status would be overly restrictive and challenging to implement. While the Commission envisions rural service providers will bid primarily on geographic licenses that overlap with their service area, the Commission does not want to restrict small rural service providers from being able to expand their service area by bidding on licenses that are outside of their service area.

107. The Commission recognizes the consumer benefits that stem from multiple providers being able to utilize the unique and highly valuable characteristics of low-band spectrum. It is therefore the Commission's goal to encourage significant competition in the Incentive Auction for licenses in rural areas. The Commission finds that the bidding credit cap will protect against a provider using a rural service provider bidding credit to win a license in a major metropolitan area. As Council Tree notes, ''[i]n Auction 97, 87 percent of the licenses sold were valued at more than $40 [million]'' and ''[s]uch caps effectively preclude DEs from acquiring medium- and large-sized urban markets.'' Moreover, the Commission finds that it would be overly cumbersome to implement a bidding credit that would vary on a provider-by-provider and market-by-market basis. Consistent with the Commission's overall goals in this proceeding, it sought to streamline and simplify the implementation of its rural service provider bidding credit where possible. For these reasons, the Commission does not limit a rural service provider bidding credit to an area where the service provider has been certified for ETC status.

108. *Rural Service Provider Bidding Credit.* The Commission's current rules provide a schedule of small business definitions and corresponding bidding credits. 47 CFR 1.2110(f). The bidding credits range from a 15 percent bidding credit to a 35 percent bidding credit. These bidding credits are based on the businesses' average annual gross revenues, and not the number of subscribers, or the number or percentage of rural counties served. AT&T, the Rural-26 Coalition, and several other rural entities propose a rural service provider bidding credit of 25 percent. Some commenters argue that the Commission should adopt a rural service provider bidding credit equal to the average credit available to small businesses—currently 25 percent—and argue that ''the funds saved by a 25% bid credit would enable rural carriers to use more of their scarce resources on build out and upgrading of their existing networks, rather than spectrum

acquisition, thereby ensuring better and faster service to rural consumers.'' The Commission notes, however, that rural service providers are already eligible to receive funding for network build-out through various Commission and Federal government programs, such as the Universal Service Fund. Moreover, rural service providers generally have greater access to capital and infrastructure than other small businesses or new entrants. Accordingly, the Commission establishes a rural service provider bidding credit of 15 percent. The Commission believes that a bidding credit of 15 percent will strike the right balance between its existing DE system where rural service providers are often unable to receive a bidding credit at all and the requested 25 percent bidding credit that may provide an existing rural service provider with an unnecessary advantage in certain markets.

109. *Small Business and Rural Service Provider Bidding Credits Will Not Be Cumulative.* An applicant is permitted to claim a rural service provider bidding credit or a small business bidding credit, but not both. While several rural stakeholders argue that the rural service provider bidding credit should be cumulative with a small business credit, the Commission does not believe that a cumulative rural bidding credit is necessary or appropriate at this time. Both of these credits are designed to be tailored to the circumstances appropriate for eligible bidders. While the Commission finds that the adoption of a rural service provider bidding credit will serve the public interest by fostering competition in rural areas, it does not believe that a provider should be permitted to ''double-dip'' and benefit from both a small business bidding credit and a rural service provider bidding credit. Indeed, many of the service providers that are now eligible for the rural service provider bidding credit have well over $55 million in annual revenues and thus have far greater access to capital than most small businesses. The Commission therefore declines to adopt a bidding credit higher than 15 percent because it is mindful of concerns of small businesses that granting higher credits could serve to undercut the effectiveness of its existing small business bidding credit program. For similar reasons, the Commission also declines to adopt a tiered approach for rural service providers. There is no evidence in the record to support a tiered credit, or that smaller rural service providers face significantly unique or different challenges than larger ones. Moreover, to the extent a smaller rural service provider would qualify as a small business, the Commission anticipates that it would elect to claim a small business bidding credit, rather than a rural service provider bidding credit. Accordingly, the Commission agrees with the AT&T and Rural-26 Joint Proposal that the rural service provider bidding credit should not be cumulative with the small business bidding credit. Therefore, an applicant must choose between one bidding credit and the other.

iii. Small Business and Rural Service Provider Bidding Credit Caps

110. *Background.* In the *Part 1 NPRM,* the Commission sought comment on various proposed changes to its DE program designed to realize more effectively the goals of providing meaningful opportunities for *bona fide* small businesses and eligible rural service providers to participate at auction, without compromising its responsibility to prevent unjust enrichment. The Commission asked whether, in an effort to achieve that balance, it should consider reducing the level of bidding credits it awards in light of its proposals to increase a DE's flexibility in other respects, including eliminating the AMR rule and increasing small business size standards. Several parties submitted additional proposals that expand the criteria for, or offer alternatives to, how the Commission evaluates DE eligibility, including proposals to limit the total dollar amount of DE bidding credits that any DE (or DE consortium) can claim in an auction through a cap on the total benefits awarded, or through another limiting metric that would tie bidding credits more closely to a typical business plan of a *bona fide* small business or eligible rural service provider. Based on the comments and proposals received in response to the *NPRM,* the Commission sought additional comment in the *Part 1 PN* on various options, including a bidding credit cap that would limit the amount of bidding credits that a DE could receive in an auction.

111. Discussion. The Commission received a range of comments on this issue in response to the *NPRM* and the *Part 1 PN.* Although some commenters oppose the imposition of any sort of limit on the amount of DE bidding credits that a DE may be awarded in an auction, several parties support adopting a cap or limit on the overall amount that may be awarded to any applicant or group of applicants. Moreover, some of the commenters opposing the imposition of a cap on the award of bidding credits appear to be more concerned by the appropriate level of any such cap than a cap as a general matter. The Commission adopts a cap on the monetary amount of DE bidding credits it will award in future auctions.

112. The Commission agrees with commenters that contend that the imposition of a cap, if properly designed, will help the very entities that it sought to benefit, as well as provide some level of assurance that bidding activity by small businesses and rural service providers is consistent with their relative business size and plans. AT&T notes, for example, that a cap ''could help to ensure that the amounts DEs are bidding are consistent with the smaller size and revenues of a small business.'' This approach is also consistent with the approach that other federal agencies have taken. The SBA, for example, limits the total dollar value of sole-source contracts that an individual participant in its 8(a) business development program may receive.

113. Commenters also argue that the implementation of a bidding credit cap may discourage entities that seek to game the Commission's rules at taxpayer expense. As Blooston Rural notes, a cap ''would serve as a substantial disincentive to truly large entities that may be tempted to configure an applicant that is designed to qualify for a small business status.'' The Rural-26 Coalition agrees, stating that a cap will ''deter large entities backed with Wall Street capital from gaming the rules and denying the U.S. taxpayers billions in revenues.'' The Commission notes that, as the cost of spectrum continues to grow, the incentives for structuring transactions to obtain bidding discounts increases significantly. Thus, while the Commission remains committed to strict enforcement of its DE rules, it believes that by imposing a bright-line cap on the overall amount of bidding credits it will award to a *bona fide* small business or eligible rural service provider, it will provide an important additional safeguard—or backstop—that will prevent misconduct in a manner that is simple and straightforward to implement, if set appropriately will not impose an artificial restriction on the amount DEs are likely to bid. The Commission therefore concurs with Tristar that ''[a]n aggregate limitation . . . does not frustrate the purposes of section 309(j), but instead assists in protecting the integrity of the DE program and the auction itself.''

114. In adopting an overall limit on the amount of bidding credits the Commission will award to any DE

applicant, it acknowledges that the effectiveness of a cap will depend, in significant measure, on how high—or low—it is set for any particular auction. To establish an appropriate amount generally, it is guided by its statutory directives to promote the ''development and rapid deployment of new . . . services for the benefit of the public, including those residing in rural areas;'' ''disseminat[e] licenses among a wide variety of applicants;'' and ensure the ''efficient and intensive use of the electromagnetic spectrum.'' 47 U.S.C. 309(j)(3)(A)–(B) and (D). Finally, the Commission notes that small businesses and rural service providers generally have different business plans and associated capital requirements that must also be considered in setting its cap amounts. In balancing these objectives and concerns, the Commission concludes that it can establish a cap on an auction specific basis in a manner that will allow *bona fide* small businesses and eligible rural service providers to participate in spectrum auctions and in the provision of service in a meaningful and measured way.

115. After carefully considering the record on this issue, and taking into account the changes the Commission makes to increase a DE's flexibility in other respects, it adopts a process for establishing a reasonable monetary limit or cap on the total amount of bidding credits that an eligible small business or rural service provider may be awarded in any particular auction. As a general matter, the Commission establishes the parameters to implement a bidding credit cap for all future auctions on an auction-by-auction basis, based on an evaluation of the expected capital requirements presented by the particular service being auctioned, and the inventory of licenses to be auctioned. The Commission resolves that the amount of the bidding credit cap for a small business in any particular auction will not be less than $25 million, and the bidding credit cap for the total amount of bidding credits that a rural service provider may be awarded will not be less than $10 million. Given the potential number of licenses and their expected value in the Incentive Auction, the Commission does not foresee it likely that any subsequent auction would include a bidding cap that exceeds the one establish for previous auctions.

116. In establishing the aggregate bidding credit cap floor for any particular auction at $25 million for each eligible small business, and $10 million for each eligible rural service provider, the Commission uses data from Auctions 66, 73, and 97 as a starting point. The Commission observes that a $25 million cap would have allowed the vast majority of small businesses to take full advantage of the Commission's bidding credit program. The Commission also notes that there is support in the record that a $25 million cap for a small business would still provide ''a significant benefit to the vast majority of small businesses and entrepreneurs participating in a spectrum auction, since it would represent a 25% discount on bids of up to $100 million.''

117. Likewise, the Commission notes that rural service providers have collectively advocated for a $10 million cap on the newly-established rural service provider bidding credit, which they claim will assist in their ability to participate successfully in competitive bidding and ensure that DE benefits are used for spectrum acquisition in rural markets. Additionally, based on past auction data for Auctions 66, 73, and 97, the Commission finds that if a 15 percent bidding credit had been offered in each of those auctions, each winning bidder self-identifying as a rural telephone company would not have been affected by the $10 million cap as applied to their respective gross winning bids. Indeed, RWA/NTCA also conclude that a ''[bidding] credit up to $10 million as proposed is sufficient and appropriate,'' based on its own review of past auction data. As such, the Commission finds that the smaller cap requested by the rural service providers reflects their more targeted approach to bidding generally, which is usually focused on competing for a few select license areas that align with their existing service territories or adjacent areas.

118. Given the different nature of their business plans and financial resources, the Commission concludes that different bidding credit caps, and the methodology for implementing them in the Incentive Auction, are warranted for small businesses and rural service providers. Rural service providers generally have targeted business plans focused primarily on a smaller number of license areas within their established service areas. Moreover, the Commission observes that some rural service providers may have greater access to capital than small businesses, including access to universal service funds and other forms of federal support. At the same time, the Commission notes that a cap would limit the benefits that a rural service provider could obtain in a service area that is predominantly urban, particularly if it seeks multiple licenses in the auction (and thereby has its bidding credits apportioned over those licenses). This point is largely offset by the fact that the substantial majority of the licenses available in the Incentive Auction include significant amounts of spectrum in rural areas.

119. The Commission disagrees with entities that believe that adoption of a cap ''would essentially end the DE program'' and could significantly limit a DE's ability to obtain spectrum in more than one market. USCC, for instance, explained that a bidding credit cap ''could prevent DEs from operating with sufficient scale to sustain itself in the industry.'' As a general matter, the Commission finds that taking an auction-by-auction approach for establishing bidding credit caps will enable it to look carefully at, among other challenges, the capitalization costs for a particular service that DEs may face in order to compete in that auction and provide service to the public. Using this process will also provide commenters with the flexibility to provide specific, data-driven arguments in support of the bidding credit caps for that particular service. The Commission also notes that its rule changes will not foreclose the ability for designated entities to participate in auctions when their auction bids fall above the cap; rather, such entities may still receive a bidding credit discount of up to designated cap for that auction and then pay the excess above that amount. Nor has USCC provided any basis for the scenario in which non-DEs will outbid the cap simply to deprive DEs of the licenses. First, because the cap is an aggregate one, rather than a per-license one, such a strategy would appear to be impracticable, particularly in auctions where anonymous bidding is utilized. More important, there is no basis for concluding that non-DEs would exceed an aggregate cap (on whatever licenses they may seek) unless they believe the licenses' value exceeds the cap—in which case doing so would promote section 309(j)'s goal of efficient and intensive use of the spectrum.

120. The Commission also disagrees with various comments that, in sum, argue that the implementation of bidding credit caps is inconsistent with the Commission's statutory mandates. The Commission finds no merit in these arguments. The Commission is vested with broad discretion when balancing various statutory objectives. Additionally, the Commission has consistently determined that section 309(j) does not charge the Commission with providing entities with generalized economic assistance or a path to success, but rather with the

responsibility and the discretion to provide opportunities for small businesses while preventing the unjust enrichment of ineligible entities. *See* Order on Reconsideration of the DE Second Report and Order, 71 FR 34272, 34276–77, June 14, 2006; Secondary Markets Second Report and Order, 69 FR 77522, 77529, December 27, 2004. The Commission further notes that the statutory goal cited by commenters requiring it to promote economic opportunity and competition by a wide dissemination of licenses is ''subject to a variety of reasonable interpretations,'' and must be balanced against a number of other competing statutory objectives. In striking that balance, ''only the Commission may decide how much precedence particular policies will be granted when several are implicated in a single decision.'' The Commission finds that appropriate bidding credit caps will protect the integrity of the DE program by providing opportunities for qualified designated entities, while mitigating the incentives for abuse, consistent with its statutory mandates.

121. Finally, the Commission declines to adopt other proposals that would restrict the amount a small business can bid at auction, or that would base a bidding credit cap on another metric such as population. The Commission believes that such proposals would be unduly burdensome on DEs to implement and might negatively affect competition, unlike those the Commission adopts. Indeed, as Blooston Rural notes, placing a limit on bid amounts is arbitrary and establishing standards based on population contravenes the long-standing economic principle that ''a license available for auction should go to the entity that values it the most.''

122. The bidding credit caps the Commission adopts will enable small businesses and rural service providers to attract capital and participate in the Incentive Auction, as well as future Commission auctions, in a meaningful way, consistent with their business plans. The Commission adopts these bidding credit caps based on its experience in administering its auctions program, and based on data regarding bidding credits DEs have utilized to date. By establishing parameters significant enough to assist eligible entities to have the opportunity to compete at auction, but reasonable enough to ensure that ineligible entities are not encouraged to undercut its rules, the Commission concludes that it achieves its dual statutory goals of benefitting DEs and at the same time preventing unjust enrichment.

123. *Adoption of DE Bidding Credit Caps for the Incentive Auction.* Given the significant advantages of the low-band spectrum licenses being auctioned, and the associated capital requirements, the Commission establishes a higher cap on the total amount of bidding credits that a small business may receive for the Incentive Auction than what it anticipates in other future auctions. Specifically, the Commission establishes a $150 million cap for small businesses and maintains a $10 million cap for rural service providers on the total amount of bidding credits that a winning bidder may receive. The Commission finds that these cap amounts are appropriate given the unique characteristics of the 600 MHz spectrum being auctioned, its analysis of past auction data, and record evidence. Further, for the purposes of the upcoming Incentive Auction, the Commission also employs a market-based differential for how the cap will be imposed on a winning DE bidder in both larger and smaller markets. Taken together, the Commission believes that these cap amounts will allow small businesses and rural service providers to attract capital and compete in the Incentive Auction in an equitable and meaningful way, consistent with their respective business plans.

124. The Commission finds that a significant upwards adjustment from the $25 million baseline for small businesses is warranted in light of the significant value of the 600 MHz spectrum to be auctioned and associated capital requirements. As the Commission indicated in the *Mobile Spectrum Holdings Report and Order,* 79 FR 39977, July 11, 2014, low-band spectrum is known to have superior propagation characteristics to mid- or high-band spectrum. Low-band spectrum is also less costly to deploy and provides higher coverage quality. As noted by T-Mobile, ''[t]he the 600 MHz spectrum is particularly valuable because it penetrates buildings more readily and covers a much wider geographic area with fewer transmitters than higher-band spectrum.'' According to CostQuest, the cost of deploying networks using mid-band spectrum (1900 MHz) would require nearly 300 percent more in total investment than a comparable network deployed using low-band spectrum (700 MHz). The Commission therefore finds that a $150 million cap is warranted given the significant difference in value between low-band and higher-band spectrum. This will ensure that smaller businesses are not disadvantaged vis-à-vis larger bidders and have the opportunity to compete in a meaningful way.

125. Based on past auction data, the Commission also finds that a $150 million cap would accommodate the bidding thresholds of a higher percentage of small business participants than the $25 million baseline would. The Commission observes, for example, that in Auctions 66, 73, and 97, nearly all of the small businesses that claimed bidding credits—for licenses in both large and small markets—would have fallen under a $150 million cap amount. In addition, the Commission notes that when applying Auction 97 prices to 10-megahertz PEA licenses (the same configuration as in the Incentive Auction), a $150 million cap would not affect a 15 percent or 25 percent bidding credit discount for any individual license bid except in the top two markets (NY and LA). The Commission therefore expects that a $150 million cap would give small businesses a meaningful opportunity to compete for a wide variety of licenses in both large and small market areas, consistent with their overall business plans.

126. While USCC suggests that the use of past auction data for determining the bidding credit cap is not an accurate reflection of the ever-increasing cost of spectrum, the Commission does not find this argument to be persuasive. Commenters, such as AT&T and RWA/NTCA, have used past auction data to support their proposed caps for the Incentive Auction. In addition, Council Tree has used past auction data to support their advocacy for certain policy positions. Moreover, as part of determining what DE benefits to adopt for a particular service, the Commission traditionally reviews the service rules for spectrum bands that have similar propagation characteristics. In the Incentive Auction for instance, the Commission determined the appropriate small business size definitions and associated bidding credits based in part on its service rules for the licenses in the 700 MHz band. Therefore, consistent with its past practices and the approach taken by several commenters in this proceeding, past auction data will be a factor, among others, in establishing a reasonable cap for DE benefits in the Incentive Auction.

127. Capping the rural service provider bidding credit at $10 million for the Incentive Auction is also appropriate based on a similar examination of past auction data and is supported by the majority of rural service providers. Assuming that these same entities will participate in the Incentive Auction, the Commission

expects that its bidding credit limits will capture nearly all of the gross winning bids of these entities thereby minimizing any negative impact on DEs in general. By establishing these caps, the Commission intends to provide *bona fide* small businesses and eligible rural service providers with sufficient flexibility to obtain the necessary capital to compete in spectrum auctions and achieve the appropriate size and scale to operate in the wireless marketplace and serve the public interest.

128. *Implementation of the DE Bidding Credit Caps, Based on Market Population, for the Incentive Auction.* To create parity in the Incentive Auction among small businesses and eligible rural service providers competing against each other in smaller markets, the Commission establishes a ceiling on the overall amount of bidding credits that any winning DE bidder may receive in connection with winning licenses in markets with a population of 500,000 or less, *i.e.,* PEAs 118 through 416. *See* Wireless Telecommunications Bureau Provides Details about Partial Economic Areas, *PEAs PN,* 79 FR 52653, September 4, 2014. Specifically, no winning DE bidder will be able to obtain more than $10 million in bidding credits for licenses won in PEAs 118–416, with the exception of PEA 412 (Puerto Rico), which exceeds the 500,000 pop threshold. To the extent a small business does not claim the full $10 million in bidding credits in the smaller markets, it may apply the remaining balance to its winning bids on larger licenses, up to the aggregate $150 million cap for small businesses.

129. The Commission expects that this approach will provide small businesses the flexibility to pursue a variety of business models that may include bidding in both large and small markets, while ensuring they compete on equal footing with rural service providers in smaller markets. The Commission also notes that this flexible approach is generally consistent with alternative proposals put forth by commenters and agree that it strikes a measured and reasonable balance to help protect against potential abuse of the DE program while also allowing larger DEs a higher cap in larger service areas.

130. The Commission determines that a market threshold based on a license area with 500,000 or less pops is consistent with record evidence, an analysis of past auction data, and its experience in auctions and licensing matters. The Commission also finds that the 500,000 population threshold provides an objective and easily administrable delineation between larger urban and smaller rural markets.

131. Several commenters strongly advocated for placing a ceiling on the amount of bidding credits that could be applied in those areas with a population of 500,000 or less. These commenters note that, in light of record support for a larger cap in urban markets, it may be advantageous to vary the cap levels for larger urban and smaller rural markets. The RWA/NTCA/Blooston Rural and Rural-26 Coalition, for example, propose using a 500,000 threshold to differentiate between such markets. The Commission concurs that a 500,000 threshold is a reasonable benchmark to distinguish between larger and smaller license areas. The Commission notes, for example, that the population density of PEAs with population of 500,000 or less correlates more closely with that of rural areas, as well as the average population of a Cellular Market Area (CMA), a smaller geographic license area favored by small and rural carriers. Specifically, the average population density of PEAs with a population greater than 500,000 (PEAs 1–117 and 412) is 333 pops/mile, whereas the average population density for the smaller PEAs (PEAs 118–416), except for 412—Puerto Rico) is 76 pops/mile. Additionally, the Commission observes that 76 pops/mile roughly corresponds with the 100 pops/mile approach it takes in defining rural areas. Given these characteristics, the Commission notes that these smaller markets are ones where rural service providers are most likely to offer service and where an opportunity to compete on equal footing is of particular importance. In addition, based on the results of Auction 97, the Commission estimates that the cap for any entity eligible with a 15 percent bidding credit or larger would not be exhausted in any these areas. In light these considerations, the Commission finds that 500,000 is a reasonable threshold and provides DEs with sufficient flexibility to adjust their strategic and capitalization demands in order to compete meaningfully in the Incentive Auction. The Commission therefore declines to implement the proposal recommended by ARC in its late-filed *ex parte* to divide the markets into thirds and to implement a $10 million cap for PEAs in the bottom third tier (*i.e.,* PEA 278 and below) or alternatively to implement a $10 million cap for PEAs with populations below 100,000. The Commission notes that ARC makes no showing as to why this alternative approach is superior or better serves the Commission's goal of establishing parity for small and rural providers competing in the smallest markets.

iv. Other Bidding Preferences/Types of Credit

132. The *Part 1 NPRM* sought comment on whether to extend bidding preferences to entities based on criteria other than business size. Specifically, the Commission sought comment on the possibility of offering credits to members of the groups named in the statute besides small businesses—*i.e.,* rural telephone companies and businesses owned by minority groups and women. The Commission also sought comment on whether to extend bidding preferences based on the provision of service to unserved/underserved areas and areas of persistent poverty, as well as to entities owned by persons who have overcome substantial disadvantages. The Commission noted that its ability to implement other types of bidding credits is constrained by both its statutory authority and standards of judicial review, and sought specific comment on how any alternative proposals could overcome such limitations. In response to suggestions submitted in response to the *Part 1 NPRM,* the Commission sought comment in the *Part 1 PN* on whether it should offer other bidding preferences or types of credits such as those ''based on criteria other than business size.''

133. With the exception of the rural service provider bidding credit, the Commission declines to adopt bidding preferences or credits based on criteria other than business size at this time. The limited record support for any of the proposals beyond the rural service provider bidding credit is insufficient to justify departure from its existing DE program. The Commission believes that repeal of the AMR rule, the expanded size standards for eligibility for the DE program, and new rural service provider bidding credit will help to address the challenges that such groups face today, including: raising capital to compete in an auction; finding a revenue stream to support network construction and business expansion; and developing a business model based on market needs.

a. Minority- and Women-Owned Businesses

134. *Background.* The Commission's ability to target bidding credits to certain types of entities is constrained by its statutory authority and constitutional standards of judicial review. Following the Supreme Court's decisions establishing judicial standards for government programs based upon gender and race, it has been the

Commission's policy to employ gender- and race-neutral provisions, offering credits instead to businesses based on the size of the business. The Commission has long recognized that many minority- and women-owned businesses are eligible for a small business bidding credit. However, the Commission has never foreclosed on the possibility of finding additional ways to directly or indirectly support opportunities for participation by minorities and women in auctions and the wireless marketplace within the bounds of its authority. In the *Part 1 NPRM,* the Commission sought comment on whether its current small business provisions are sufficient to promote participation by businesses owned by minorities and women and, if not, how additional provisions to ensure participation by minority- or women-owned businesses could be crafted to meet the relevant standards of judicial review. While commenters did not advocate for preferences targeted specifically toward minority- and women-owned businesses, several urged the Commission to adopt race- and gender-neutral updates to the DE rules that would aid all eligible entities, including minorities and women.

135. *Discussion.* The Commission declines to adopt a bidding credit for minority- and women-owned businesses. The Commission notes that no party advocated for such a preference, nor provided evidence to demonstrate that such a credit could meet the constitutional standards for review. Instead, the Commission agrees with commenters that updating its DE rules should provide small businesses—including enterprises owned by minorities and women—a better on-ramp into the wireless business.

b. Unserved/Underserved Areas and Persistent Poverty Preferences

136. *Background.* The Commission sought comment in the *Part 1 NPRM* on whether the Commission should extend bidding credits to winning bidders that deploy facilities and provide service to unserved or underserved areas, or to those that provide service to persistent poverty counties. The Commission also sought comment on its tentative conclusion that section 309(j) of the Act authorizes it to offer bidding credits using these criteria. Further, the Commission encouraged commenters to offer data-driven suggestions and address any potential implementation issues.

137. *Discussion.* The Commission declines to adopt specific additional bidding credits on the basis of whether the license area correlates with unserved/underserved areas or persistent poverty counties at this time. Some commenters support a bidding credit for persistent poverty areas. Others argue for a bidding credit in conjunction with addressing unserved/underserved areas, or that the Commission should focus on strengthening its current DE program, rather than considering the adoption of new bidding credits. It remains a goal of the Commission, through its various universal service and other programs and policies, to promote the deployment of broadband facilities and services to unserved and underserved areas and persistent poverty counties. The Commission furthers those goals by adopting a rural service provider bidding credit and repealing the AMR rule. According to the Department of Agriculture's Economic Research Service (ERS), a large portion of unserved or underserved areas and persistent poverty counties are located in rural areas. Thus, the rural service provider bidding credit the Commission adopts is intended to better ensure that consumers in unserved/underserved areas and persistent poverty counties have access to more competition and improved services. Nevertheless, the Commission will continue to monitor the effectiveness of the proposals it adopts in advancing the deployment of spectrum-based services in unserved/underserved and persistent poverty areas. To the extent the policies the Commission adopts is not sufficient, it encourages parties to provide it with contrary evidence so that it may reexamine these policies based on a more complete record.

c. Overcoming Disadvantages Preference

138. *Background.* In response to renewed interest raised in the Incentive Auction proceeding, the *Part 1 NPRM* sought further comment on a recommendation by the Commission's Advisory Committee on Diversity for Communications in the Digital Age (Advisory Committee) to implement a bidding preference for persons or entities who have overcome substantial disadvantage (referred to as an overcoming disadvantages preference or ODP). The Commission sought detailed and specific comment on its statutory authority to adopt such a preference and the benefits of doing so, as well as eligibility for, and administration of, the preference. The Commission also noted that the Advisory Committee's proposal raised a number of challenges to be resolved before any ODP could be designed and implemented. The Commission received only two comments on this issue, which are divided on the desirability and feasibility of an ODP.

139. *Discussion.* The Commission declines to adopt the Advisory Committee's ODP proposal. The *Part 1 NPRM* reflects the Commission's uncertainties about how eligibility for such a preference could be defined and/or administered in the auction context. The comments the Commission received in response to the *Part 1 NPRM* did not alleviate any of its concerns about the complexity in implementing such a preference. In addition, the policy decisions adopted—including the repeal of the AMR rule, the expansion of the small business bidding credit thresholds, and the new rural service provider bidding credit—will benefit those persons or entities who have overcome substantial disadvantage. These decisions are intended to promote the provision of spectrum-based services by all *bona fide* small businesses and eligible rural service providers, including those that have overcome a substantial disadvantage. The Commission also believes that this approach is simpler than adoption of the Advisory Committee's ODP proposal. While the ODP Recommendation provided a non-exhaustive list of disadvantages, it is not clear what proof should be required from those individuals or entities seeking to receive such a preference and how to apply the ODP on a neutral basis. The Commission is also concerned that its review of such a claim would involve a costly and lengthy process. Accordingly, the Commission declines to adopt the Advisory Committee's ODP proposal.

d. Tribal Lands Bidding Credit

140. *Background.* NTCH urges the Commission to consider ending its tribal lands bidding credit, and the Commission sought additional comment on this topic in the *Part 1 PN.* The tribal lands bidding credit program awards a discount to a winning bidder for serving qualifying tribal land that has a wireline telephone subscription rate equal to or less than 85 percent based on Census data. NTCH argues that tribal lands may not merit *per se* qualification as a disadvantaged category because some tribes have multiple business enterprises and some receive subsidies from grant programs to target telecommunications deficits. NTCH provides no citation or reference to empirical data to substantiate its position. NTCH suggests instead that the Commission determines the need for a tribal lands bidding credit on a case-by-case basis to avoid granting bidding credits that may be ''unnecessary and

actually unfair to others,'' but does not explain specifically how such an individualized qualification process might be administered. Several tribal entities involved in the telecommunications industry detail the chronic lack of wireless services on tribal lands, explain that tribal entities may encounter unique challenges in participating in spectrum auctions, and oppose any changes to the tribal lands bidding credit program.

141. *Discussion.* The Commission declines to adopt any modifications to its tribal lands bidding credit in this proceeding. A substantial number of comments and reply comments from various tribes and tribal entities uniformly oppose NTCH's suggestion. Several tribal entities involved in the telecommunications industry detail the chronic lack of wireless services on tribal lands, explain that tribal entities may encounter unique challenges in participating in spectrum auctions, and oppose any changes to the tribal lands bidding credit program. Numerous reply comments voice support for these comments and asked that NTCH's suggestion be rejected. The Commission has been presented with no evidence or information suggesting that its policy of providing tribal lands bidding credits has been rendered unnecessary or does not further its objective in promoting further deployment and use of spectrum over tribal lands. Thus, the Commission declines to make any alterations to the established tribal lands bidding credits here.

C. Unjust Enrichment

142. *Background.* Under the Commission's rules, a DE seeking approval of a transfer of control or an assignment of a license acquired with a bidding credit to a non-DE within five years after its initial issuance must reimburse the government a portion of the bidding credit. This reimbursement obligation is governed by a five-year unjust enrichment schedule, with the amount of repayment decreasing over time.

143. As part of its effort to balance the policy objectives for the DE program, the Commission sought comment in the *Part 1 NPRM* on whether any changes are needed to strengthen its unjust enrichment rules. The Commission invited comment on whether the existing five-year unjust enrichment period and repayment schedule continue to provide sufficient safeguards against potential misuse, or whether there is a need to extend the schedule to ten years or some other time period. In addition, the Commission sought comment on the ability of a small business to raise capital and participate at auction, and to provide service, if the Commission were to repeal the AMR rule, as proposed in the *NPRM,* and also tighten the unjust enrichment rules—particularly when compared to the existing unjust enrichment rule. The Commission also asked whether there are other unjust enrichment provisions it should consider, such as requiring full repayment of benefits if a small business loses eligibility prior to meeting the applicable construction requirement, and whether a different reimbursement percentage (*i.e.,* less than 100 percent) is preferable.

144. In the *Part 1 PN,* the Commission sought comment on some of the alternative viewpoints expressed by parties in response to the *Part 1 NPRM.* The Commission asked for additional comment on whether the unjust enrichment period should be extended to apply for a specified number of years (*e.g.,* ten years), to the entire license term, or linked to an interim construction milestone. The Commission also asked if there are other alternatives it should consider, such as revisiting the percentage amounts associated with the unjust enrichment schedule. In addition, the Commission requested comment on whether it should, as T-Mobile suggests, require the repayment of any profit or some multiple of the bidding credit received, and invited commenters to discuss whether the DE benefits associated with any and all of a DE's licenses should be forfeited if a DE loses its eligibility. The Commission invited comment on whether it should consider T-Mobile's proposal to impose additional build-out and reporting obligations specific to DEs that would require them to determine ''tangible steps toward development'' and, if so, what the appropriate timeframe(s) for such a requirement would be. The Commission also asked whether there are any other options it should consider to prevent spectrum warehousing and encourage expeditious spectrum build-out, such as requiring repayment of some percentage of a bidding credit if a DE fails to meet a construction benchmark. Finally, the Commission asked commenters to address any tradeoffs related to these proposals, including the extent to which they would restrict a DE's ability to access capital, prevent abuse of the designated entity program, and avoid unjust enrichment.

145. The Commission received a range of comments in response to its proposals in both the *Part 1 NPRM* and *Part 1 PN.* Most parties oppose any extension of the unjust enrichment period, with many maintaining that the existing five-year period sufficiently protects against unjust enrichment while at the same time providing small businesses with the flexibility to obtain access to capital. Several of these parties also highlight the potentially adverse impact that extending the unjust enrichment period could have on their ability to retain capital to operate their businesses. RWA and WISPA, for example, warn that an extended unjust enrichment period locks DEs into business plans and hinders new entrants. Council Tree maintains that extending the period to ten years ''would be debilitating for investors and effectively end DE bidding at higher levels.'' M/C Partners submits that ''[t]he practical effect of extending the unjust enrichment period beyond five years and removing the payback tiers would be to discourage venture capital investments in DEs,'' while Columbia Capital notes that ''limiting a DE's flexibility to transfer or assign licenses during the entire term likely would rule out investments in DEs by such funds.'' MMTC similarly states that ''in a rapidly changing industry, no one will invest in a company from which exit is impossible . . . for a decade.'' MMTC further notes that an extension of the unjust enrichment period to ten years would further hamper or eliminate a DE's ability to raise and retain capital and operate its business with the same level of flexibility afforded to other businesses in the wireless industry. M/C Partners and Columbia Capital maintain that extending the unjust enrichment period to ten years would effectively foreclose private equity investments in DEs because most venture capital and private equity funds have a ten-year investment horizon, with investments typically occurring in the first few years, average realization periods of three to seven years from the time of initial investment, and the last few years devoted to planning an exit. The DE Coalition, RWA, WISPA, KSW, and Atelum likewise express concern that an extension of the unjust enrichment period could limit a small business' access to capital. As KSW states in opposing a ten-year unjust enrichment period, ''ten years is a lifetime in wireless, and financial institutions are far less willing to provide money for a ten-year period.'' CCA recognizes the need for strong unjust enrichment protections, but opposes proposals to extend the unjust enrichment penalties to apply throughout the entire license term because it could cause DEs to experience difficulties in attracting and

obtaining outside investment which would constrain small business participation in auctions. CCA submits that ''adopting a rigorous two-pronged eligibility combined with the current five-year unjust enrichment restriction and payment schedule represents a sensible calibration of policy objectives that strikes a balance between increasing participation of small businesses in auctions and promoting the deployment of spectrum-based services.'' RWA similarly states that a five-year period ''nicely balances the competing goals of preventing unjust enrichment to ineligible entities with small and rural carriers' need for flexibility and access to capital.''

146. A few parties, however, support making certain adjustments to strengthen its unjust enrichment rules. T-Mobile and Native Public support extending the unjust enrichment period to the full license term. T-Mobile also advocates requiring licensees to repay the windfall profit, plus interest, from the sale of a license obtained with a bidding credit, while Taxpayer Advocates supports requiring a DE that leases or sells a significant portion of spectrum acquired with a bidding credit within the first five years to pay back all or part of the discount it received. Native Public supports allowing a license acquired with a bidding credit to be sold during the license term only by repaying the bidding credit used to obtain the license or selling the licenses to the tribe or ANC whose DE eligibility was used to obtain the credit. T-Mobile also supports adopting a build-out requirement that is uniquely applicable to DEs or tethered to service-specific performance requirements to prevent spectrum warehousing and to promote facilities-based service. Specifically, T-Mobile asks that the Commission require DEs to show some evidence of build-out activity within one year after acquiring a license or clearing incumbent users.

147. Most commenters, however, strongly oppose any build-out requirements that are uniquely applicable to DEs. Council Tree argues that if a unique build-out restriction is imposed on DEs, the associated licenses would be less valuable and investor capital would be more difficult to obtain, while KSW maintains that it would be ''counter-productive to require enhanced build-out showings from those who are least equipped to do so'' and that there is no reason to apply a heightened standard to DEs in this regard. Rural Telcos maintain that the Commission's rules should prevent DE program abuse before licenses are granted, rather than imposing additional regulatory burdens on *bona fide* DEs (*i.e.,* rural telephone companies) that can least afford them. Although CCA supports the concept of requiring DEs to ensure they are utilizing their spectrum in order to deter speculators from using bidding credits to acquire and warehouse spectrum, it cautions against adopting any requirements that would hamstring small carriers' ability to compete or raise capital for the auction, or create undue burdens for DEs that are legitimately using spectrum. CCA therefore urges the Commission to avoid impairing smaller competitors through accelerated build-out schedules or expansive coverage requirements that are disproportionately onerous for smaller entities. USCC states that, in addition to imposing burdensome obligations exclusively on those that are least equipped to deal with them, treating DEs differently in this manner could also lead to other harms. USCC notes, for example, that based on the currently anticipated schedule for the Incentive Auction, the 600 MHz band will be cleared about one to two years before the expected rollout of 5G; a non-DE licensee could delay construction until 5G becomes available, however, if a DE is required to demonstrate some level of build-out within a year after clearing, it would be forced to begin building out prior to the rollout of 5G even though, without the participation of the rest of the industry, 4G equipment for the band would not be available. USCC submits that as a result, DE licensees would not be able to comply with an accelerated build-out despite their best efforts. Tristar, on the other hand, maintains that DEs that are not rural telephone companies should not be held to the same build-out standards as non-DEs and should instead be given a much longer build-out timeframe and the ability to ''save'' all licenses through build-outs over some portion of the aggregate population of their licenses.

148. Proponents of a rural service provider bidding credit support applying the same unjust enrichment rules adopted for small business bidding credits to any adopted rural service provider bidding credit with some modest changes. Specifically, Blooston Rural, Rural Coalition, and RWA/NTCA support requiring an unjust enrichment payment if a rural service provider licensee assigns or transfers a license acquired with a bidding credit to a non-eligible entity within the unjust enrichment period. These parties maintain, however, that neither an unjust enrichment payment nor the prohibition should apply to a license recipient that is (1) another rural telephone company or rural telco subsidiary/affiliate with a wireless or wireline presence in the applicable license area, or (2) an independent wireless ETC certified in the original license area with fewer than 100,000 subscribers.

149. *Discussion.* After a careful review of the record, the Commission concludes that its existing rules provide a sufficient safeguard to ensure that designated entity benefits are provided only to *bona fide* small businesses and eligible rural service providers. The Commission therefore declines to make any adjustments to the unjust enrichment period and repayment schedule. The Commission agrees with commenters that increasing the unjust enrichment period will impede the ability of DEs to both access capital and participate in auctions. As WISPA notes, investors in the telecommunications industry typically want to recover their investments within five years. RWA also notes that a five-year unjust enrichment period allows small businesses and rural carriers to quickly respond to rapid industry changes, changing business models, and capital demands, thereby providing them with the necessary flexibility to compete against larger carriers. Overall, the record does not provide the Commission with sufficient evidence to demonstrate that an extension of the current unjust enrichment period will yield greater protections without causing undue harm to *bona fide* small businesses and eligible rural service providers. To the contrary, the record is replete with evidence from the numerous parties that oppose extending the unjust enrichment period that it will impede DEs' ability to raise and retain capital and successfully participate in auctions.

150. The Commission's current unjust enrichment rules—in combination with the other actions it takes—balances commenters' concerns regarding the unjust enrichment of ineligible entities with the need to provide increased operational flexibility to DEs given the evolving wireless marketplace. Specifically, its adoption of a totality-of-the-circumstances approach in evaluating the eligibility of DEs will allow the Commission to consider all the agreements and relationships that a DE maintains with its investors. In addition, its decision to limit the ability of a DE's disclosable interest holders to use the spectrum in any way during the five-year unjust enrichment period where the nexus of use is more than 25 percent and the interest in the DE is ten percent or greater will prevent the benefits of the program from flowing to

the financial investors in a DE. As its revised rules demonstrate, the Commission will remain vigilant in undertaking a careful review of all applications by entities seeking to acquire or retain bidding credits. In so doing, the Commission expects to properly execute its statutory responsibility to continue to prevent unjust enrichment of ineligible entities.

151. The Commission also declines to adopt T-Mobile's proposal that impose additional build-out and reporting obligations specific to DEs. There is very limited support for such a requirement in the record, and the few parties that support it offer no evidence of the benefit it would provide or the harm that will result in the absence of any such requirement. Conversely, the record contains ample evidence from the numerous parties that oppose such a requirement that it is likely to be burdensome, both administratively and in terms of their ability to raise capital. After weighing how the proposal may affect a small business's ability to access capital, prevent abuse of the designated entity program, and avoid unjust enrichment, the Commission is persuaded that any potential benefit that might be gained from adopting such a requirement a would be outweighed by the harms it would cause. The Commission agrees with commenters opposing such a requirement that a construction requirement specifically targeted to DEs would likely impose unnecessary administrative and operational burdens with no demonstrated benefit. This requirement could also have the effect of hindering initiatives to spur additional marketplace competition by *bona fide* small businesses and eligible rural service providers. Accordingly, the Commission does not adopt any DE-specific construction requirements.

152. *Application of Unjust Enrichment Rules to Recipients of Rural Service Provider Bidding Credit.* The Commission will apply its existing unjust enrichment rules to licensees that take advantage of the new rural service provider bidding credit. Therefore, a licensee that assigns or transfers a license acquired with a rural service provider bidding credit to an entity that meets the eligibility requirements for such credit will not be required to make an unjust enrichment payment. But if the licensee assigns or transfers a license acquired with a rural service provider bidding credit to an entity that is not eligible for such a credit within the unjust enrichment period, an unjust enrichment payment will be required.

D. Alternatives To Promote Small Business Participation in the Wireless Sector

153. In the *Part 1 NPRM,* the Commission sought comment on suggestions that would enable the DE program to remain a viable mechanism for small businesses to gain flexibility to access capital, compete in auctions, and participate in new and innovative ways to provision services in a mature wireless industry. Several commenters offered alternatives they contend the Commission could pursue to facilitate small business access to benefits in both the auction and secondary market contexts. AT&T suggests that providing incentives for secondary market transactions or virtual networks may offer a more direct path to including more valuable small businesses in the telecommunications industry and may be a more effective mechanism for DE participation in wireless markets than facilitating participation in auctions due to the cost of licenses and capital needed to build networks. Blooston Rural advocates allowing a winning bidder to deduct from the auction purchase price the *pro rata* portion of its winning bid payment for any area that is partitioned to a rural telephone company or cooperative to provide another avenue for rural service providers to obtain licenses for smaller areas that correspond to their existing service areas. CCA and ARC agree that Blooston Rural's proposal would benefit DEs by providing incentives for partitioning and promoting secondary market transactions, but ARC states that the incentives would be even greater if the winning bidder received a 125 percent credit for partitioning to any DE, not just a rural telco. NTCH states that diverse ownership has been shown to enhance competition, spur innovation in services, permit local-based service to customers, and spread the benefits of spectrum to a broader segment of the population, and proposes giving a 50 percent ''diversity credit'' to bidders who can deliver this important diversity benefit by acquiring licenses. ARC agrees that such a credit would promote wide dissemination of licenses as required by the Communications Act.

154. Based on the comments received in response to the *NPRM,* the Commission sought comment in the *Part 1 PN* on these alternatives. The Commission also asked whether strengthening its build-out requirements and improving processes to reclaim licenses provide opportunities for small businesses to gain access to spectrum and increase diversity of license holders, and whether there are alternative frameworks that it should consider to promote a diverse telecommunications ecosystem, including incentives for secondary market transactions or virtual networks that could provide a more direct path into the industry for all entities, including DEs. RWA/NTCA support Blooston Rural's rural partitioning bidding credit proposal, submitting that it would encourage larger carriers to facilitate rural carrier participation in the provision of wireless services. MMTC proposes that the Commission consider a variety of options that would add to a reformed DE program, among them, consideration of secondary market transactions as a factor in evaluating market competition and in reviewing waiver requests relating to ownership (including in the mergers and acquisitions and IP transition contexts), restoration of its former tax certificate policy, and establishment of a new bidding credit or installment payment program for entities that engage in secondary market transactions. The National Urban League suggests that any carrier that participates in secondary market transactions with designated entities could be provided a bidding credit for future auctions. NTCH suggests that the concentration of spectrum in a handful of companies can be reduced by offering significant discounts to entities that hold less than 20 megahertz of spectrum in a given market and that are not also counted as nationwide providers as defined by the Commission in the *Part 1 NPRM,* and reiterates its earlier proposal to provide a 50 percent ''diversity credit'' to such entities. CCA asks the Commission to consider supplemental measures to small business bidding credits that address the challenges smaller carriers face in the secondary market for spectrum, and proposes that it provide incentives in the secondary market by offering carriers a license term extension in exchange for partitioning or disaggregating unused portions of their spectrum to small carriers or to serve rural areas.

155. Based on the record, the Commission declines at this time to adopt any of the alternatives recommended by interested parties.

156. *Rural Partitioning Bidding Credit.* The Commission declines to adopt a rural partitioning bidding credit for entities that partition their licenses area to a rural telephone company or cooperative. The Commission notes that none of the commenters supporting this approach provided any details about how such a proposal could be implemented, and it is concerned that

the proposal would be complicated to implement without providing any meaningful benefit. Moreover, the Commission concludes that the policy concern the proposal seeks to address, which relates to facilitating access to spectrum by rural service providers, is sufficiently addressed by its adoption of a rural service provider bidding credit.

157. *Diversity Bidding Credit.* To avoid having an excessive concentration of licenses held by a small number of providers, NTCH proposes a 50 percent ''diversity credit'' for entities that hold less than 20 megahertz of spectrum in the market at issue and who are not also counted as nationwide providers. The Commission notes that in the *Mobile Spectrum Holdings Report and Order,* it considered and rejected requests to offer bidding credits based on the level of spectrum holdings. The Commission finds that the very limited record in this proceeding offers no new evidence to support disturbing its prior conclusion.

158. *Enhanced Build-Out Rules.* Based on the record, the Commission declines to adopt any enhanced build-out rules to give smaller providers an opportunity to obtain spectrum that has not been built out by a licensee. The Commission acknowledges the importance of its build-out rules; however, it did not receive any specific comments on this question in response to its inquiry and, therefore, concludes that the record is not sufficiently developed to warrant any the adoption of any enhanced build-out rules at this time.

159. *Incentives for Secondary Market Transactions or Virtual Networks.* AT&T suggested in its comments on the *NPRM* that providing incentives for secondary market transactions or virtual networks may offer a more direct path for more valuable small businesses in the telecommunications industry and may be more effective than facilitating participation in auctions due to the cost of licenses and capital needed to build networks. However AT&T did not offer any specific proposals in connection with this suggestion, and did not further comment on this topic in response to the *Part 1 PN.* MMTC suggested in response to the *Part 1 PN* that the Commission consider a variety of options to augment a reformed DE program. The Commission declines to adopt MMTC's recommendation that it consider secondary market transactions as a factor in deciding whether to grant a carrier rule waivers relating to ownership. In its Mobile Spectrum Holdings proceeding, the Commission addressed commenters' recommendations that it adopt a similar consideration in the spectrum holdings context, namely, that elements of a proposed transaction that facilitate diversity be considered in balancing the benefits and harms of the transaction. The Commission declined in the *Mobile Spectrum Holdings Report and Order* to adopt a formal set of guidelines, noting that it retains the authority to consider all factors that could affect the likely competitive impact of a proposed transaction. The Commission finds that the limited record in this proceeding does not provide sufficient justification to support adopting such a requirement, and therefore declines to adopt MMTC's recommendation. The Commission notes again that it retains the right to consider such factors in evaluating specific future transactions, as it has ''encouraged the use of secondary market transactions . . . to transition unused spectrum to more efficient use and allow network providers to obtain access to needed spectrum for broadband deployment.'' The Commission also declines to adopt MMTC's recommendation that it consider secondary market transactions as a factor in determining whether to report to Congress that the wireless marketplace is competitive. The Commission notes that the Wireless Telecommunications Bureau recently sought comment on the role of secondary market transactions in a public notice in connection with the annual report on the state of competition in mobile wireless. Accordingly, the Commission will address the issue of secondary market transactions as a factor in determining whether access to sufficient spectrum exists for multiple service providers to be able to provide robust competition in the context of that proceeding. With regard to MMTC's other recommendations, MMTC did not offer any specific details about how they might be implemented, nor did the Commission receive any comment from other commenters on this topic or on MMTC's recommendations. Moreover, the Commission observes that MMTC's recommendation that it restore its previous tax certificate policy appears to be outside the scope of its authority. The Commission therefore concludes that the record is not sufficiently developed to allow it to act on this suggestion.

160. *License Term Extension in Exchange for Partitioning.* The Commission declines to adopt CCA's proposal that it provide licensees with a license term extension in exchange for partitioning or disaggregating unused portions of their spectrum to small carriers or to serve rural areas. The Commission notes that CCA did not offer any details about how such a proposal could be implemented. Moreover, the Commission did not receive comments from other any party on this proposal. The Commission therefore concludes that the record is not sufficiently developed to allow it to act on CCA's proposal.

E. DE Reporting Requirements

161. *Background.* Pursuant to 47 CFR 1.2110(n), the Commission requires DE licensees to file an annual report with the Commission that includes, at a minimum, a list and summaries of all agreements and arrangements, extant or proposed, that relate to eligibility for DE benefits. The list must include the parties (including affiliates, controlling interests, and affiliates of controlling interests) to each agreement or arrangement, as well as the dates on which the parties entered into each agreement or arrangement. DEs are required to file a report for each of their licenses no later than, and up to five business days before, the anniversary of the date of license grant.

162. In the *Part 1 NPRM,* the Commission proposed to repeal the annual DE reporting requirement, stating that the information that DEs are required to include in their annual reports is duplicative of information that DEs provide in their auction and license applications. The Commission also observed that for licensees with multiple auction licenses, each having a different grant date, the burden of the annual reporting requirement is exacerbated by the obligation to file multiple reports each year.

163. *Discussion.* In light of the increased flexibility the Commission grants to DEs in this proceeding, it concludes that its ability to oversee the award of DE benefits, and its responsibility to prevent unjust enrichment, will be better served by retaining the annual reporting requirement, as modified and clarified. While the reporting requirement of 47 CFR 1.2110(n) is similar to other requirements in its competitive bidding rules, it is not identical to any of them. *See* 47 CFR 1.2110(j), 1.2112(b), 1.2114. Moreover, the changes the Commission adopts will eliminate the reporting redundancies that two commenters mentioned. The Commission is also cognizant of the comments filed by the DE Coalition and MMTC, urging it to rely on its reporting requirements as part of an effective system of checks and balances on waste, fraud, and abuse in the DE program.

164. In deciding to retain the annual reporting requirement, the Commission

has carefully evaluated the concerns of Blooston Rural and RWA, both of which support repeal of the annual DE reporting requirement. The objections of Blooston Rural and RWA are twofold—that licensees with multiple auction licenses, each having a different grant date, must file multiple annual reports numerous times per year, and that the information provided under the annual reporting requirement is duplicative of information required to be reported by other Commission rules. To resolve these concerns, the Commission amends the annual DE reporting requirement and provides four clarifications.

165. To eliminate the burden for some DEs of having to file more than one annual report at various times of the year, the Commission will modify its annual reporting requirement to require that all annual reports be filed no later than September 30 of each calendar year. This annual report will reflect the status of each individual license subject to unjust enrichment requirements that is held by a particular licensee as of August 31 of that same calendar year including all proposed or executed agreements or arrangements affecting DE benefit eligibility. This September 30 deadline will apply regardless of the grant date of an individual license. This rule modification will reduce the administrative and related burdens that the annual reporting requirement might pose for certain small businesses or rural service providers without undermining its ability to obtain the information contained in the DE reports.

166. The Commission also specifies the following transition from its current annual report filing process to the newly-adopted modified requirement. Any designated entity licensee that would have had a report due between the release date of this order and the applicable effective date of the amended rule may defer filing its annual report until September 30, 2016. This transition will enable the Commission to balance the goal of minimizing the administrative burden on DEs with its objective of having current DE information on file.

167. In addition, the Commission modifies its rules to reduce the administrative burden on DEs and address questions that the Commission has received in the past from DEs. First, the 47 CFR 1.2110(n) annual reporting requirement applies only to licenses acquired with a DE bidding credit and still held subject to unjust enrichment obligations. *See* 47 CFR 1.2111. Second, when a DE assigns or transfers a license to another DE, the DE that holds the license on September 30 of the year in which the application for the transaction is filed is responsible for complying with 47 CFR 1.2110(n). Finally, filers need not list agreements and arrangements otherwise required to be reported under 47 CFR 1.2110(n) so long as they have already filed that information with the Commission and the information on file remains current. In such a situation, the filer must include in its annual report both the ULS file number of the report or application containing the current information and the date on which that information was filed. The Commission also clarifies that the annual DE reporting requirement, and all DE reporting requirements, will, on the effective date of the rules it adopts apply to rural service providers as well as to other DEs.

168. Finally, the Commission stresses that, in light of the increased flexibility and benefits available to DEs under the rules it adopts, it will continue to rely on the information produced pursuant to the DE reporting requirement to help it monitor the eligibility of those awarded DE bidding credits. Accordingly, the Commission reminds DEs that it expects them to comply fully with the annual reporting requirement, as modified and clarified herein. DEs also remain obligated to provide the Commission with all of the information relevant to their initial and ongoing eligibility to acquire and retain DE benefits under its other reporting requirements, in a timely and accurate manner, which will be particularly important given the flexibility it has afforded them to determine eligibility for designated entity benefits on a license-by-license basis. Toward that end, the Commission reminds DEs that they have an ongoing obligation to provide information regarding any agreements entered into after the license grant(s) that, had they been in existence, would have had to be disclosed at the long-form application stage to demonstrate DE eligibility, including, for example, agreements between a DE and its investors that are relevant for evaluating control or spectrum use agreements that are relevant for compliance with its newly-adopted attribution rules. *See* 47 CFR 1.2110(j), 1.2112(b), 1.2114.

F. MMTC's White Paper Requests

169. *Background.* In February 2014, MMTC submitted a White Paper detailing several policy recommendations to advance minority and women spectrum license ownership. In addition to requesting the elimination of the AMR rule, an increase in bidding credits, and a substantive review of proposed DE rules, the White Paper requested that the Commission take action in several additional areas. In the *Part 1 NPRM,* the Commission sought comment on MMTC's additional proposals, including its tentative conclusion that some of them are outside the scope of this proceeding, including: (1) Incorporating diversity and inclusion in the Commission's public interest analysis of mergers and acquisitions and secondary market spectrum transactions; and (2) supporting increased funding for and statutory amendments to the Telecommunications Development Fund (TDF). The Commission notes that MMTC's request with respect to ''ongoing recordkeeping of DE performance'' refers to ''retain[ing] specific information about the [minority-owned business enterprises] and [woman-owned business enterprises] status of bidders, in addition to the small business status.'' The Commission has sought comment in WT Docket No. 13–135 on the need to collect information on the participation of minority and women-owned enterprises in the mobile wireless industry, pursuant to similar MMTC requests.

170. *Discussion.* Outside of the request to eliminate the AMR rule as discussed elsewhere, the Commission declines to adopt MMTC's other proposals. Besides the comments regarding the repeal of the AMR rule, the Commission received two comments on the other proposals including in MMTC's White Paper. The DE Coalition urged the Commission to adopt MMTC's proposals to incorporate diversity and inclusion into the Commission's public interest analysis of mergers and acquisitions and secondary market spectrum transactions, complete the *Adarand* studies updating the section 257 studies released in 2000, and finally regularize procedural requirements. The National Urban League argues that the Commission should use proceeds from the incentive auction to ''reinvigorate and fully underwrite the Telecommunications Development Fund.'' The Commission adopts its proposal to repeal the AMR rule and replaces it with a two-pronged analysis. The lack of a record on MMTC's proposals other than repeal of the AMR rule suggests that this is the key proposal in MMTC's White Paper and the Commission believes that repeal of the AMR rule and replacement with a two-pronged analysis adequately addresses MMTC's concerns regarding minority and women spectrum license ownership. The Commission is committed to providing innovative,

bona fide small businesses—including minority- and women-owned businesses—the opportunity to participate meaningfully in the Incentive Auction, and to spur additional competition, investment and consumer choice in the wireless marketplace. The Commission believes that the other decisions being made here will promote the overall objectives that are the goals of MMTC within the bounds of its authority. Accordingly, except for repeal of the AMR rule, the Commission declines to adopt MMTC's proposals.

III. Other Part 1 Considerations

171. The Commission continues to standardize and streamline its competitive bidding rules in advance of the Incentive Auction by adopting other revisions to its Part 1 competitive bidding rules. These revisions will improve transparency and efficiency of the auctions process, as well as ensure that appropriate safeguards are in place to maintain the integrity of the auctions process. Specifically, the Commission revises the former defaulter rule consistent with the relief granted to applicants for Auction 97, codifies a prohibition on multiple auction applications by the same entities, and imposes limits on the filing of applications by commonly-controlled entities. The Commission also prohibits joint bidding arrangements, while permitting certain pre-existing operational, business, and pro-competitive relationships and makes related modifications to the rule prohibiting certain communications. Finally, the Commission harmonizes the modifications adopted with the Part 1 competitive bidding rules adopted in past proceedings.

A. Former Defaulter Rule

172. *Background.* In the *Part 1 NPRM,* the Commission proposed to modify its former defaulter rule. The former defaulter rule requires an applicant that has defaulted on any Commission license or has been delinquent on any non-tax owed to any federal agency, but has since remedied all such defaults and delinquencies, to pay an upfront payment that is 50 percent more than the normal upfront payment amount in order to be eligible to bid in an auction, provided that the applicant is otherwise qualified. The Commission tentatively concluded that, given the tremendous growth of the wireless industry since the inception of the rule, the time was ripe to modify it. Consistent with the provisions in the *Former Defaulter Waiver Order* adopted for applicants in Auction 97, the *Part 1 NPRM* proposed to narrow the reach of the Commission's former defaulter rule by codifying four exclusions from the general rule that were first announced in the *Former Defaulter Waiver Order. See Part 1 NPRM,* 79 FR at 68186.

173. The Commission also sought comment in the *Part 1 NPRM* on several approaches to limit the scope of individuals and entities that an auction applicant must consider when determining its status as a former defaulter. *See Part 1 NPRM,* 79 FR at 68188–89. In the subsequent *Part 1 NPRM,* the Commission asked for comment on additional viewpoints and suggestions from commenters, specifically whether to adopt an additional exclusion based on an applicant's credit rating, as suggested by AT&T or, alternatively, whether to eliminate the former defaulter rule entirely, as originally proposed by NTCH and Sprint. Nearly all commenters support the *NPRM's* proposal to codify the four exclusions articulated in the *Former Defaulter Waiver Order.* Some, such as AT&T and Chugach, request modest changes, such as the adoption of another exclusion based on an applicant's ''investment grade'' credit or to index the proposed $100,000 threshold for inflation. Moreover, AT&T, CCA, CTIA, and Chugach contend that the current rule sweeps too broadly and imposes unnecessary and disproportionate financial burdens on auction applicants.

174. *Discussion.* In an effort to simplify the auction process and minimize the administrative and implementation costs for bidders, the Commission adopts the *NPRM's* proposed changes to the former defaulter rule, none of which any party opposes. Specifically, the Commission excludes any cured default on a Commission license or delinquency on a non-tax debt owed to a Federal agency for which any of the following criteria are met: (1) The notice of the final payment deadline or delinquency was received more than seven years before the relevant short-form application deadline (Notice to a debtor may include notice of a final payment deadline or notice of delinquency and may be express or implied, and for purposes of the certifications required on a short-form auction application, a debt will not be deemed to be in default or delinquent until after the expiration of a final payment deadline. *See, e.g.,* Letter to Cheryl A. Tritt, Esq., from Margaret W. Wiener, Chief, Auctions and Spectrum Access Division, Wireless Telecommunications Bureau, 19 FCC Rcd 22907 (2004)); (2) the default or delinquency amounted to less than $100,000; (3) the default or delinquency was paid within two quarters (*i.e.,* six months) after receiving the notice of the final payment deadline or delinquency (on which the date of receipt of the notice of a final default deadline or delinquency by the intended party or debtor is the triggering mechanism for verifying receipt of notice); or (4) the default or delinquency was the subject of a legal or arbitration proceeding and was cured upon resolution of the proceeding. This approach aims to balance commenters' concerns that the rule is overly broad with the Commission's long-standing goals of ensuring that auction participants are financially responsible. Additionally, the Commission will implement its revised rules on a prospective basis, including for the Incentive Auction. *See generally Incentive Auction R&O, 79 FR 48442.*

175. The Commission declines to adopt AT&T's proposal to exempt an applicant from former defaulter status if it has an ''investment grade'' credit rating by a credit agency such as Moody's and Standard and Poor's, or to accept letters of credit from a Federal Deposit Insurance Corporation member institution for those businesses that do not have a credit rating. No commenters squarely addressed these ideas. Investment credit ratings, standing alone, are not necessarily indicative of an entities' financial wherewithal to participate in a Commission auction. Moreover, as a practical matter, the Commission concludes that implementing the AT&T proposal, as part of its time-limited auction application review process, would be administratively burdensome and unnecessary given the additional flexibility the Commission provides with the changes. Inevitably, the Commission recognizes there may be unique or unusual circumstances that may not squarely fall under one of the exclusions the Commission adopts. Consistent with the waiver standard of 47 CFR 1.925, the Commission will therefore consider requests for clarification and/or waiver of former defaulter status under its rules.

176. The Commission adopts in part commenters' proposals to narrow the scope of the individuals and entities considered for purposes of the former defaulter rule. CCA contends that the scope should be limited to those that are in a position to affect whether the applicant meets its auction-related financial responsibilities. NTCH would narrow the scope of the rule to controlling shareholders or executive officers of the former defaulter or affiliate thereof. No commenters,

however, oppose tailoring the scope of the individuals and entities evaluated under the rule. The Commission agrees that the relevant inquiry should be limited to those individuals and entities that have positions of control over the auction applicant or licensee and may be able to influence the ability of that entity to fulfill its auction-related financial obligations. The Commission will therefore adopt a controlling interest definition for purposes of the certifications required under 47 CFR 1.2105(a)(2) including the certification as to whether an applicant has ever been in default on any Commission license or been delinquent on non-tax debt owed to any Federal agency. *See* 47 CFR 1.2105(a)(4)(i), as adopted herein. Under the definition for this rule, a ''controlling interest'' includes individuals or entities with positive or negative *de jure* or *de facto* control of the licensee. Under this new rule, the defaults or delinquencies of certain individuals and entities will no longer be attributed to the auction applicant for purposes of any former defaulter determination. By narrowing the scope of the former defaulter rule to attribute only defaults or delinquencies of controlling interests, the Commission will ensure that the underlying purposes of the rule are met, while minimizing costs for auction applicants.

177. Finally, the Commission rejects calls of NTCH, Sprint, and AT&T to eliminate the former defaulter rule. NTCH and Sprint reason that the rule is ''ineffective'' and ''counterproductive,'' and point to a lack of evidence to support any material benefit of the rule. AT&T suggests that the Commission could use other existing mechanisms in lieu of the rule, such as the Commission's Red Light Display System database. While the Commission recognizes that the former defaulter rule was adopted during the nascent stages of the auction program and mobile wireless industry, the Commission believes that the underlying policy reasons for the rule continues to be relevant given the importance of ensuring that auction participants are financially responsible. Because the integrity of the auctions program and the licensing process dictates requiring a more stringent financial showing from former defaulters, the Commission declines to revisit these long-standing policies.

B. Joint Bidding Prohibition

178. Consistent with Congressional directives and the Commission's policy goals, the Commission has adopted policies regarding joint bidding to promote competition in the mobile wireless marketplace and between bidders in auctions. These rules and policies sought to provide additional safeguards designed to reinforce existing laws and facilitate detection of harmful anticompetitive conduct without being unduly burdensome so that they hinder parties from gaining access to the capital necessary to participate in Commission auctions. The current joint bidding rules were adopted at the time when the mobile wireless industry was nascent. Since that time, and particularly in the past decade, the wireless marketplace has changed significantly. After consideration of the record, the Commission amends its rules to prohibit joint bidding. The Commission seeks to prohibit certain arrangements involving auction applicants and relating to the licenses being auctioned that address or communicate bids or bidding strategies, including arrangements regarding price and specific licenses on which to bid, as well as any such arrangements relating to the post-auction market structure. The Commission excludes from the prohibition certain agreements, including those that are solely operational and those the Commission finds will promote competition. These changes will provide additional clarity for potential applicants while affording opportunities for non-nationwide providers and DEs to pool their resources to promote more robust competition in future auctions and in today's evolving mobile wireless marketplace.

179. In the *NPRM,* the Commission observed that joint bidding and other arrangements have the potential to promote competition by enabling greater participation in auctions. However, the Commission recognized that because some joint bidding and other competitor collaborations could reduce competition between participants post-auction, they raise the risk that spectrum licenses acquired at auction could be distributed in a manner that could harm the public interest. Therefore, the Commission tentatively concluded that joint bidding arrangements between nationwide providers likely would raise competitive concerns that would outweigh any public interest benefits from such arrangements. In contrast, the Commission tentatively concluded that joint bidding arrangements between non-nationwide providers were far less likely to lead to competitive harm or otherwise harm the public interest. The Commission sought comment on the policies and procedures that should apply to bidding arrangements between a single nationwide provider and other entities. Specifically, the Commission sought comment on whether any limits should apply to these types of arrangements or whether the Commission should continue to review such arrangements on a case-by-case basis.

180. In the *Part 1 PN,* the Commission sought further comment on specific, alternative proposals offered into the record in response to the *NPRM.* The Commission also sought to expand the record on its proposals in the *NPRM* to prohibit parties to a joint bidding agreement from bidding separately on licenses in the same market, prohibit communications between joint bidders when bidding on licenses in the same market, and prohibit any individual or entity from serving on more than one bidding committee.

181. *Discussion. Promoting Competition in Auctions and in the Marketplace.* In the *NPRM,* the Commission stated that when assessing the competitive effects of joint bidding and other arrangements, it must ensure that its policies and rules facilitate access to spectrum licenses in a manner that promotes competition within auctions and in the current wireless marketplace. In light of the changes in the structure of the wireless marketplace in recent years, the Commission generally agrees with commenters that updates to its joint bidding rules are necessary to promote more robust competition in future auctions and in today's evolving mobile wireless marketplace. In addition, joint bidding arrangements among separate applicants in an auction generally raise the risk of undesirable strategic bidding during auctions, such as by means of ''bid stacking.'' By ''bid stacking,'' the Commission refers to coordinated bidding activity among bidders to place multiple bids on the same licenses in an auction round. In light of the evolution of the marketplace and the potential future risks of undesirable strategic and/or anticompetitive behavior, the Commission takes this opportunity to refine the definition of joint bidding arrangements, prohibit joint bidding arrangements generally, and adopt certain bright-line rules to promote competition. More specifically, the Commission prohibits joint bidding arrangements between applicants (including any party that controls or is controlled by, such applicants), regardless of whether the applicants are nationwide or non-nationwide providers. In addition, the Commission prohibits joint bidding arrangements involving two or more nationwide providers as well as joint bidding arrangements involving a nationwide and non-nationwide provider, where

any one of the parties is an applicant for auction.

182. The Commission notes that it has always made clear with respect to its rules and policies governing joint bidding that ''conduct that is permissible under the Commission's Rules may be prohibited by the antitrust laws,'' review under which is subject to other and differing standards under the Sherman and Clayton Acts. The Commission's auction procedures public notices for specific auctions caution that ''[c]ompliance with the disclosure requirements of 47 CFR 1.2105(c) will not insulate a party from enforcement of the antitrust laws.'' Auction applicants that are found to have violated the antitrust laws or the Commission's rules in connection with their participation in the competitive bidding process may be subject to forfeiture, prohibition from auction participation, and other sanctions.

183. *Joint Bidding Arrangements Between Nationwide Providers.* Consistent with its tentative conclusion in the *NPRM,* the Commission finds that joint bidding arrangements between any two or more nationwide providers, of which there are currently four, have a potential to harm the public interest by negatively affecting the competitive bidding process during an auction as well as downstream competition in the provision of mobile wireless services. The Commission notes that, while not all parties advocate the same responsive measures, the record does not include significant disagreement with its analysis of the underlying risk factors present in today's marketplace—high degrees of concentration, high barriers to entry, and high margins. Collaboration between nationwide providers raises the risk of reduced competition in the greatest number of markets both during an auction and afterwards. In light of the record before it, and the underlying risk factors present in the marketplace today, the Commission prohibits joint bidding arrangements between nationwide providers. For purposes of the Commission's competitive bidding rules, the entities that qualify as nationwide providers will generally be identified in procedures public notices released before each auction.

184. AT&T, Verizon Wireless, King Street Wireless, Tristar, and Spectrum Financial argue that the Commission should prohibit joint bidding arrangements altogether, including between nationwide providers, because such a restriction would be the most effective way to prevent anticompetitive bidding coordination in auctions. In contrast, Sprint and T-Mobile argue that joint bidding arrangements between some nationwide providers can promote post-auction competition and have the potential to increase consumer welfare. Apparently focused on the upcoming Incentive Auction, Sprint specifically proposes that joint bidding arrangements should be permitted in areas in which parties to an agreement collectively hold less than 45 megahertz of sub-1 GHz spectrum. T-Mobile argues that the Commission should not adopt any bright-line restrictions on joint bidding, and should instead address all joint bidding arrangements on a case-by-case basis. T-Mobile additionally comments that if the Commission would limit joint bidding arrangements in some form, then T-Mobile supports Sprint's proposal to permit joint bidding arrangements where parties to an agreement hold less than 45 megahertz of sub-1 GHz spectrum. This proposal, in effect, would allow joint bidding between Sprint and T-Mobile, the two nationwide providers currently without significant low-band spectrum holdings. CCA and T-Mobile support the proposal to prohibit parties to a joint bidding agreement from bidding separately on licenses in the same market.

185. As the Commission stated in the *NPRM* and based upon the record before it, the Commission finds that joint bidding arrangements between nationwide providers present significant risks by enabling market competitors to reduce competition within auctions in a large number of geographic areas. Nationwide providers, whether or not they have significant low-band spectrum holdings, all have significant resources and actively compete against one another across the country. Joint bidding among nationwide providers, who are the entities most likely to bid in auctions for licenses across the entire country, could significantly reduce rivalry within auctions to the detriment of the Commission's objectives for auctions, and increases the risk of facilitating anticompetitive behavior by dividing markets on a national scale, thus reducing competition in numerous markets.

186. The Commission has recognized the significance of access to low-band spectrum for promoting competition in the marketplace, as argued by Sprint and T-Mobile, but the Commission disagrees with their arguments that allowing them to enter into joint bidding arrangements with each other to obtain low-band spectrum is a necessary or appropriate response to promote competition. The Commission is mindful of the anticompetitive risk factors present in the marketplace today, but it finds that the risks of anticompetitive behavior by joint bidding between any nationwide providers outweigh the potential benefits that might come from allowing Sprint and T-Mobile, or any other nationwide providers that lack significant low-band spectrum holdings, to bid jointly. Therefore, the Commission adopts its proposal to prohibit nationwide providers from entering into joint bidding arrangements in auctions.

187. The Commission also finds that the risk of anticompetitive behavior, including market division, from these arrangements is not limited to circumstances where both nationwide providers are applicants in an auction. Accordingly, the prohibition against joint bidding between nationwide providers extends to bidding arrangements in which one (or more) of the nationwide providers is not itself an applicant in an auction.

188. *Joint Bidding Arrangements Between Non-Nationwide Providers.* In the *NPRM,* the Commission tentatively concluded that the benefits of joint bidding between non-nationwide providers outweighed the risks of public interest harms, given the structure of the wireless marketplace, the current distribution of spectrum, and the lesser ability of non-nationwide providers to engage in anticompetitive behavior. After review of the record before it, the Commission prohibits joint bidding arrangements between non-nationwide providers as separate applicants in an auction, given the risk of undesirable strategic bidding during auctions, but allows the use of joint ventures and consortia as single applicants. For these purposes, ''non-nationwide provider'' refers to a provider of communications services that is not a ''nationwide provider.''

189. In response to the *NPRM* and the *Part 1 PN,* CCA, NCTA, ARC, and RWA emphasize the challenges faced by small and rural providers and these parties contend that joint bidding arrangements between non-nationwide providers are generally pro-competitive. Several commenters note the financial difficulty that smaller rural providers face in bidding on larger geographic areas on their own, and argue that given the high cost of spectrum, joint bidding arrangements between non-nationwide providers can enable smaller companies to compete effectively for licenses that they would otherwise be unable to acquire on their own.

190. By contrast, as with joint bidding arrangements between nationwide providers, AT&T, Verizon Wireless, King Street Wireless, Tristar, and Spectrum Financial argue that the

Commission should prohibit joint bidding arrangements among non-nationwide providers because of the risk of undesirable strategic behavior. Some of these parties argue that if smaller providers want to pool resources, they can do so by forming joint ventures or bidding consortia and bidding through those entities.

191. The Commission recognizes both the need to prohibit arrangements between multiple bidders to coordinate bidding during an auction, and the potential benefits, with relatively small risks, from non-nationwide providers working together to pool resources or otherwise realize financial economies of scale in its auctions. The Commission also recognizes, as some commenters point out, that joint ventures and bidding consortia allow smaller providers to combine resources, thus promoting competition in the mobile wireless marketplace and facilitating competition between bidders at auction. In the Commission's judgment, these arrangements can be an effective means of allowing smaller entities to compete in auctions, and, ultimately, promote post-auction competition. The Commission finds that joint ventures and consortia can capture the benefits sought by smaller providers wishing to combine resources while not risking the potential for anticompetitive behavior during the course of an auction. Accordingly, while the Commission prohibits joint bidding arrangements among non-nationwide providers as separate applicants in an auction, it will allow the use of joint ventures and consortia in light of the potential for smaller providers to use consortia and joint ventures to realize the benefits of pooling resources that are sometimes associated with some kinds of joint bidding arrangements. For purposes of competitive bidding, consortium and joint ventures are defined in 47 CFR 1.2105(a)(4), as adopted herein. In addition, the Commission does not prohibit joint bidding arrangements between non-nationwide providers where only one of the non-nationwide parties is the entity filing an auction application and other(s) are non-applicants.

192. *Joint Bidding Arrangements Between Nationwide and Non-Nationwide Providers.* In the *NPRM,* the Commission sought comment on possible policies and procedures that could enable joint bidding between nationwide and non-nationwide providers to be in the public interest and suggested that it might consider these arrangements on a case-by-case basis. After review of the record, the Commission prohibits joint bidding arrangements between nationwide and non-nationwide providers, rather than attempting to review such arrangements on a case-by-case basis.

193. In this proceeding, some commenters agree that the Commission should adopt a case-by-case approach to reviewing arrangements between nationwide and non-nationwide providers, but also stress the importance of providing pre-auction clarity to bidders regarding the permissibility of such agreements. A number of commenters urge the Commission to adopt bright-line rules to protect the integrity of auctions, promote efficient pre-auction application review, and avoid undue delay of auctions. The Commission agrees with commenters that providing pre-auction certainty to bidders regarding permissible joint bidding arrangements will facilitate competitive auctions. However, because the Commission would need to determine with finality during pre-auction application review whether any particular joint bidding arrangement should be permitted during the auction, it finds that a case-by-case review of all such arrangements as part of that review process runs an unacceptable risk of significantly delaying auctions and therefore would not be in the public interest.

194. In adopting bright-line rules governing joint bidding arrangements between nationwide and non-nationwide providers, the Commission first observes that such arrangement among separate applicants raise the same concerns with respect to the risk of undesirable strategic bidding during auctions. Accordingly, the Commission prohibits joint bidding arrangements between nationwide and non-nationwide providers when parties to the arrangements are filing separate applications. Further, as with the prohibition against joint bidding between nationwide providers, the Commission's prohibition here extends to joint bidding arrangements that include providers that are not themselves an applicant in an auction. In particular, joint bidding arrangements that involve a nationwide provider could significantly reduce rivalry within auctions to the detriment of the Commission's objectives for auctions.

195. In addition, unlike its determination with respect to arrangements between non-nationwide providers, the Commission does not permit nationwide and non-nationwide providers to participate in auctions through a joint venture. While the Commission recognizes that joint ventures formed between nationwide providers and non-nationwide providers could provide additional opportunities for those entities to participate in auctions, the potential for reduced rivalry within the auction outweighs any such benefits.

196. *Implementation of Joint Bidding Prohibition.* To promote clarity and certainty and to achieve its stated goals, the Commission clarifies that ''joint bidding arrangements'' for these purposes include arrangements relating to the licenses being auctioned that address or communicate, directly or indirectly, bidding at the auction, bidding strategies, including arrangements regarding price or the specific licenses on which to bid, and any such arrangements relating to the post-auction market structure. Due to the potential benefits to smaller providers and for promoting post-auction competition, the Commission is permitting DEs to join in bidding consortia and non-nationwide providers to form certain joint ventures to apply to participate at auction as a single entity. The Commission notes that ''non-nationwide provider'' refers to any provider of communications services that is not a ''nationwide provider.'' The Commission also makes clear that the prohibition does not encompass agreements that are solely operational in nature, that is, agreements that address operational aspects of providing a mobile service, such as agreements for roaming, spectrum leasing and other spectrum use arrangements, or device acquisition, as well as agreements for assignment or transfer of licenses, provided that any such agreement does not both relate to the licenses at auction and address or communicate, directly or indirectly, bidding at auction (including specific prices to be bid) or bidding strategies (including the specific licenses on which to bid or not to bid) or post-auction market structure. Consistent with its new approach to joint bidding agreements, the Commission also revises its rule prohibiting communications relating to bids or bidding strategies. To provide transparency, the Commission retains its long-standing requirement regarding disclosure of agreements to which auction an applicant is party, but revises it to more effectively monitor its new prohibition on joint bidding agreements.

197. As spelled out in the revised rules, each auction applicant must certify on behalf of itself and any party that controls, or is controlled by, such applicants, that it has not entered and will not enter into a joint bidding arrangement with any other applicant(s), with any nationwide provider that is not an applicant, or, if the applicant is a nationwide provider,

with any non-nationwide provider that is not an applicant, other than agreements that fall within the limited exceptions the Commission provides. Under 47 CFR 1.2105, as adopted herein, the Commission's rules will now contain a definition of ''controlling interest'' that includes all individuals or entities with positive or negative *de jure* or *de facto* control of the licensee. The Commission recognizes that certain agreements and relationships may exist prior to an auction as well as that communications of information other than bids and bidding strategies may be permitted to continue during an auction if made pursuant to and within the scope of specified types of agreements that are excluded from the general prohibition and disclosed in the relevant short-form application(s). Under the Commission's revised prohibited communications rule, parties to these specific kinds of agreements may communicate during this ''quiet period'' provided that any communications are within the scope of the pre-existing agreement that is disclosed on the applicants' short-form auction applications and do not convey specific bids or the substance of an applicant's bidding strategy.

198. The Commission does not include within its definition of prohibited joint bidding arrangements any agreement that is solely operational in nature, including agreements relating to roaming, spectrum leasing and other spectrum use arrangements, or device acquisition, as well as any agreements for assignment or transfer of licenses, provided that any such agreement expressly does not both relate to the licenses at auction and address or communicate directly or indirectly bidding at auction (including prices) or bidding strategies (including the specific licenses on which to bid) or post-auction market structure. Thus, when an applicant certifies to its compliance with its competitive bidding rules, it is certifying that any operational agreement that it may have does not involve a shared bidding strategy and therefore is solely operational. Similarly, any agreement for the transfer or assignment of licenses existing at the deadline for filing short-form applications will not be regarded as a prohibited arrangement, provided that it does not both relate to the licenses at auction and include terms or conditions regarding a shared bidding strategy and expressly does not communicate bids or bidding strategies. Further, the Commission notes that agreements between an applicant and another entity solely for funding purposes, *i.e.,* with no agreements with regard to bids, bidding strategies, or post-auction market structure relating to the licenses at auction, are not prohibited joint bidding arrangements.

199. The prohibition on joint bidding agreements does not prevent certain agreements to form consortia or joint ventures, which result in one party applying to participate in an auction. In particular, to promote competition within auctions and in the marketplace, the Commission continues to allow DEs to form and use consortia and are allowing non-nationwide providers to form joint ventures to bid in auctions. Eligible entities may use a consortium or joint venture to pool resources and realize financial economies of scale to compete more effectively in its auctions, and, ultimately, in the marketplace. In order to address the potential for undesirable strategic bidding through the use of these vehicles, the Commission specifies that: (1) DEs can participate in only one consortium in an auction, which shall be the exclusive bidding vehicle for its members in that auction, and (2) non-nationwide providers may participate in an auction through only one joint venture, which also shall be the exclusive bidding vehicle for its members in that auction. These provisions should effectively ensure that each auction participant, whether bidding individually, or through consortium or joint venture, has one bid per license per round.

200. The Commission also revises its rule prohibiting certain communications in light of its new rules prohibiting joint bidding agreements. Its revised prohibition on communications prohibits an applicant from communicating bids or bidding information, either directly or indirectly, with any other auction applicant, with any nationwide provider that is not an applicant, or, if the applicant is a nationwide provider, with any non-nationwide provider that is not an applicant. The revised rule provides limited exceptions for communications within the scope of any arrangement consistent with the exclusions from its rule prohibiting joint bidding, provided such arrangement is disclosed on the applicant's short-form. An applicant may continue to communicate pursuant to any pre-existing agreements, arrangements, or understandings that are solely operational or that provide for a transfer or assignment of licenses, provided that such agreements, arrangements or understandings do not involve the communication or coordination of bids (including amounts), bidding strategies, or the particular licenses on which to bid and provided that such agreements, arrangements or understandings are disclosed on its application. Moreover, as discussed elsewhere, if an applicant has a non-controlling interest with respect to more than one application, the Commission requires the applicants to certify that it has established internal control procedures to preclude any person acting on behalf of the applicant from possessing information about the bids or bidding strategies of more than one applicant or communicating such information with respect to either applicant to another person acting on behalf of and possessing such information regarding another applicant. The Commission cautions, however, that, as with certifications submitted to it in other contexts, submission of such certification in an application will not outweigh specific evidence that a communication violating its rules has occurred, nor will it preclude the initiation of an investigation when warranted.

201. *Authorized Bidders.* On a separate but related issue, the Commission sought comment in the *Part 1 PN* on a proposal to prohibit an individual from serving as an authorized bidder for more than one auction applicant. Commenters generally agree with this proposal, and the Commission adopts it here. This prohibition ensures that an individual is not in a position to be privy to bidding strategies of more than one entity in the auction, and therefore not a conduit, intentional or not, for bidding information between auction applicants.

202. *Non-Controlling Interests.* The Commission recognizes that in some circumstances entities may have non-controlling interests in other entities and both entities may wish to bid in the auction. In so far as there is no overlap between the employees in both entities that leads to the sharing of bidding information, such an arrangement may not implicate its concerns over joint bidding among separate applicants. Such an arrangement, however, could allow for the non-controlling interest or shared employee to act as a conduit for communication of bidding information unless the applicants establish internal controls to ensure that bidding information would not flow between them. To address this possibility and ensure that such arrangements do not serve or appear as conduits for information, the Commission adopts a rule requiring all applicants to certify that they are not, and will not be, privy to, or involved in, in any way the bids or bidding strategy of more than one auction applicant. Commenters generally agree with the proposal to

require a more comprehensive certification process. The Commission's new rules provide that an applicant can certify that it has established procedures to preclude its agents, employees, or related parties, from possessing information about the bids or bidding strategies of more than one applicant or communicating such information regarding another applicant. The Commission cautions, however, that submission of such certification by an applicant will not outweigh specific evidence that a communication violating its rules has occurred, nor will it preclude the initiation of an investigation when warranted.

C. Prohibition on Applications By Commonly Controlled Entities

203. Background. The Commission has long had a practice of prohibiting the same individual or entity from submitting multiple short-form applications in any Commission auction. In the *Part 1 NPRM,* the Commission proposed to codify this established procedure and sought comment on its proposal. The Commission noted that the prohibition protects against the burden of duplicative, repetitious, or conflicting filings. The *Part 1 NPRM* expressed concern that the same individual or entity could potentially use multiple short-form applications to engage in anticompetitive bidding activity by manipulating elements of the auction process. The *Part 1 NPRM* invited comment on the related issue of whether to permit the filing of short-form applications by commonly controlled entities that could bid on any of the same licenses. In doing so, the Commission acknowledged that auction participation by commonly controlled applicants potentially could serve legitimate business purposes while also presenting possible risks to the auction process.

204. In the *Part 1 PN,* the Commission solicited input on commenters' proposals suggesting that applicants should be limited in holding ownership interests in multiple auction applicants. Specifically the Commission sought comment on how to define any such ownership limits or limits on financial investments by one entity in other auction applicants, including what attribution standards might be implemented in such a context.

205. Several commenters note that where an investor holds non-controlling interests in multiple auction applicants, such an arrangement could facilitate undesirable strategic bidding at auction. T-Mobile asserts that entities sharing non-controlling cognizable interests could engage in problematic behavior and argues that the Commission should address the potential for coordinated behavior by bidders that are linked by common attributable interests. C Spire points out that ''an applicant that bids on a standalone basis but that also has multiple non-controlling investments in other applicants may be privy to and participate in the financing and bidding strategy of multiple applicants.'' KSW favors a ''reasonable'' prohibition on multiple auction entries by related parties and proposes to prohibit parties from holding equity in multiple auction applicants, but would allow the holding of interests in multiple applicants where such interest does not exceed a ''reasonable'' threshold and in cases ''where the party at issue is pulled into the auction and has no awareness or participation of bidding strategies.'' Spectrum Financial proposed an ownership limit on cross-owned bidders of something ''much less than controlling interest, certainly less than 50 percent.'' The Commission addresses concerns about applicants with shared non-controlling interests above through its prohibition on joint bidding and its revisions to its prohibited communications rule.

206. *Discussion. Duplicate auction applications.* The Commission confirms its long-standing prohibition on the filing of more than one auction application by the same individual or entity. That is, if a party submits multiple short-form applications for any license(s) in a particular auction, only one of its applications can be found to be complete when reviewed for completeness and compliance with the Commission's rules. This prohibition will minimize unnecessary burdens on the Commission's resources by eliminating the need to process duplicative, repetitious, or conflicting applications. This rule will also protect against a party manipulating the auction by placing bids through two bidding entities. Accordingly, the Commission concludes that its decision to codify its long-standing prohibition is in the public interest.

207. *Applications by entities controlled by the same individual or set of individuals.* Consistent with its prohibition on joint bidding agreements the Commission will generally permit any entity to participate in a Commission spectrum auction only through a single bidding entity. This means that the Commission will no longer permit the filing of applications by entities controlled by the same individual or set of individuals. The Commission has previously recognized that the participation of commonly controlled entities in an auction may serve legitimate business purposes because such entities may have different business plans, financing requirements, or marketing needs, while acknowledging such situations might create risk to the competitiveness of the auction process. The Commission notes, however, that such determination was made in the context of an auction conducted without the use of anonymous bidding where the identities of competing bidders were identified in each bidding round. Under the limited information procedures the Commission has used in more recent auctions, certain information on bidder interests, bids, and bidder identities that typically had been revealed prior to and during prior Commission auctions are withheld until after the close of the auction. The approach the Commission adopts is consistent with the views of commenters that broadly supported the *NPRM's* proposal to prohibit the filing of short-form applications by entities under the common control of a single individual or set of individuals in a particular geographic license area or overlapping areas. Sprint notes that this change should enhance the transparency of Commission auctions and minimize anti-competitive bidding activity. Some commenters, however, suggest that this approach does not go far enough because the rule does not address situations when applicants with lesser degrees of shared ownership agree to coordinate bids. The Commission disagrees because these concerns are now addressed by the prohibition on joint bidding agreements. The prohibition on a single party, or commonly controlled parties, from filing multiple applications is designed to ensure that auction participants bid in a straightforward manner. Consistent with its newly-adopted prohibition on joint bidding agreements, this restriction will apply across all short-form applications in a particular auction without regard to the licenses or geographic areas selected.

208. The Commission will determine common control for purposes of this prohibition using the controlling interest principle set out in 47 CFR 1.2105(a)(4)(i), as adopted herein. Under this newly adopted definition, a ''controlling interest'' includes individuals or entities with positive or negative *de jure* or *de facto* control of the licensee. This new rule will allow an applicant that has a disclosable non-controlling interest holder in another applicant to participate separately in an auction provided each applicant certifies that it has established internal

control procedures to preclude any person acting on behalf of the applicant from possessing information about the bids or bidding strategies of more than one applicant or communicating such information with respect to either applicant to another person another person acting on behalf of and possessing such information regarding another applicant. The Commission cautions, however, that, as with certifications submitted to it in other contexts, submission of such certification in an application will not outweigh specific evidence that a communication violating its rules has occurred, nor will it preclude the initiation of an investigation when warranted.

209. The Commission concludes that implementation of the principle that an entity may generally participate in bidding only through a single auction applicant will promote transparency in Commission auctions and will promote straightforward bidding activity by separate bidding entities. A transparent process will promote participation and competition in its future auctions, which is vital to ensuring the Commission meets its statutory goals. The Commission finds therefore that this prohibition is in the public interest.

210. *Limited Exception to Commonly Controlled Entity Limitation for Existing Rural Partnerships.* The Commission establishes a limited exception to the general prohibition on multiple applications by commonly controlled entities for existing rural partnerships. A broad set of rural interests have expressed concern that this prohibition could adversely impact rural telephone companies that may have an ownership interest in more than one licensee in a particular market. As the Rural-26 Coalition explains, ''historic B Block cellular partnerships are a readily identifiable group of entities that were created as part of the cellular settlement process for rural wireline carriers established by the Commission in CC Docket No. 85–388.'' Without such an exception, its new rule could limit participation in auctions by such partnerships and the rural telephone companies that comprise those rural wireless partnerships. The Rural-26 Coalition points out that an ''issue arises primarily with rural telcos that have telephone exchange areas in more than one Rural Service Area (RSA), and therefore ended up a part of more than one cellular RSA partnership as a result of the cellular B Block settlement process that applied to wireline companies in the mid to late 1980s.'' Such settlements provided that each telephone carrier operating in a particular RSA would hold a partnership interest in a partnership to operate the B Block cellular license. Often such rural wireless partnerships were structured with each partner holding a general partnership interest with one of the general partners serving as managing partner. Because a rural telephone company may have operated telephone exchanges in more than one RSA, such company may be a partner in multiple rural wireless partnerships. The Commission recognizes that such long-standing partnerships and their component rural telephone companies may each seek to participate in Commission auctions with different bidding objectives and that the unique ownership structures of such partnerships should not be an obstacle to these entities separate participation, particularly where, the Commission believes that the anticompetitive concerns underlying the general prohibition are unlikely to be implicated.

211. Under this limited exception to its governing commonly controlled entities rule for existing rural partnerships, each qualifying rural wireless partnership and its individual members will be permitted to participate separately in an auction. For purposes of this rule, a qualifying rural wireless partnership is one that was established as a result of the cellular B block settlement process established by the Commission in CC Docket No. 85–388 in which no nationwide provider is a managing partner or a managing member of the management committee, and partnership interests have not materially changed as of the effective date of the *Part 1 Report and Order.* The Commission's use of ''materially changed'' in regard to any changes over time in the composition of the rural wireless partnership is intended to allow this exception to apply even if the partnership has undertaken *de minimis* changes or partners have dropped out. A partnership member would qualify if it is a partner or successor-in-interest to a partner in a qualifying partnership that does not have day-to-day management responsibilities in the partnership and holds 25 percent or less ownership interest, and certifies that it will insulate itself from the bidding process of the cellular partnership and any other members of the partnership (other than expressing prior to the deadline for resubmission of short-form applications the maximum it is willing to spend as a partner). Such individual qualifying members of a rural wireless partnership may bid separately at auction, in addition to the rural wireless partnership itself.

D. Miscellaneous Part 1 Revisions

212. *Background.* In the *NPRM,* the Commission proposed changes to 47 CFR 1.2111 and 1.2112, both of which are in Part 1, Subpart Q, of its rules, the subpart that generally governs competitive bidding proceedings to assign spectrum licenses. The Commission received no comments on these proposals.

213. *Discussion. 47 CFR 1.2111.* The Commission proposed to repeal the first two paragraphs of 47 CFR 1.2111. The Commission proposed to repeal 47 CFR 1.2111(a), under which applicants for assignments or transfers during the first three years of a license term must provide the Commission with detailed contract and marketing information. As the Commission discussed in the *NPRM,* this requirement appears to burden licensees without providing a corresponding benefit to the Commission or the public. The Commission also proposed to repeal 47 CFR 1.2111(b), a never-used unjust enrichment payment requirement for broadband PCS C and F block set-aside licenses. In the absence of opposition to either of these proposals, the Commission adopts them both.

214. *47 CFR 1.2112.* The Commission proposed to modify 47 CFR 1.2112 to clarify the auction application requirements for reporting an entity's percentage ownership in the applicant and in FCC-regulated entities. The Commission proposed further changes to specify application requirements for bidding consortia. Finally, the Commission proposed to correct two errors in the rule caused by the inadvertent substitution of an incorrect paragraph in the Code of Federal Regulations publication of the rule for the correct one published in the **Federal Register** summary of the *DE Second Report and Order,* 71 FR 26245, May 4, 2006. The first error was the addition of a requirement that DE short-form applicants list and summarize all their agreements that support their DE eligibility, a requirement that the Commission had intended to apply only to long-form applicants. The Commission proposed to repeal this requirement for the short-form application. The second error was the deletion of a requirement that DE short-form applicants list the parties with which they have lease or resale arrangements for any of the DE applicants' spectrum licenses. The Commission proposed to reinstate this requirement. In the absence of opposition to any of these proposed

changes to 47 CFR 1.2112, the Commission adopts them all.

IV. Order on Reconsideration of the First Report and Order in WT Docket No. 05–211

215. *Background.* In this and the next two sections, the Commission addresses pending matters in WT Docket No. 05–211. In this *Order on Reconsideration of the CSEA and Competitive Bidding Report and Order,* the Commission resolves two petitions for reconsideration filed in response to the 2006 amendments to its consortium exception to the attribution requirements of 47 CFR 1.2110. Prior to 2006, the rules were silent as to whether consortium members would continue to enjoy the attribution exception when filing a long-form applications and being granted licenses. Under the Commission rules for determining eligibility for size-based bidding credits, the Commission allows parties that individually qualify as small businesses to form consortia and to apply for and participate in spectrum auctions together without being required to attribute their gross revenues to one another. 47 CFR 1.2110(b)(3)(i).

216. In the 2006 *CSEA and Competitive Bidding Report and Order,* 71 FR 6214, February 7, 2006, the Commission modified the consortium exception to its attribution rules for determining an applicant's eligibility for small business bidding credits. After receiving no opposition to its proposals offered in the *2005 CSEA and Competitive Bidding NPRM,* 70 FR 43372, July 27, 2005, the Commission adopted all three of the modifications discussed in its notice. Thus, the Commission amended its rules to require that (1) consortium members file individual long-form applications for their respective, mutually agreed-upon license(s), following an auction in which the consortium has won one or more licenses; (2) two or more consortium members seeking to be licensed together for the same license(s), or the disaggregated or partitioned portions thereof, form a legal business entity, such as a corporation, partnership, or limited liability company, to hold the license(s); and (3) any such business entity to comply with the applicable financial limits for eligibility. The Commission explained that a newly formed legal entity comprising two or more consortium members that did not qualify for as large a sized-based bidding credit as that claimed by the consortium on its short-form application would be awarded a bidding credit, if at all, based on the entity's eligibility for such credit at the long-form filing deadline. The Commission also clarified that the consortium exception is available only to short-form applicants and not to prospective licensees, assignees, or transferees.

217. In adopting the changes, the Commission observed that the consortium exception had seldom been used, perhaps in part because of insufficient direction from the Commission as to how members of consortia that win licenses could be formally organized and how they could hold their licenses. The Commission also explained that the rule changes should ''invest the consortium exception with greater transparency, thereby promoting clearer planning by smaller entities, while continuing to allow them to enhance their competitiveness with efficiencies of scale and strategy.'' The Commission noted as well that ensuring that licenses are granted only to legal business entities would facilitate enforcement of the Communications Act and of Commission rules and policies, particularly in the event of a disagreement among consortium members.

218. *Discussion.* The Commission denies the two petitions for reconsideration filed in response to the 2006 amendments to the consortium exception, one by NTCA and the other by Blooston Rural, and retain the rule modifications. While neither party filed comments in response to the *CSEA and Competitive Bidding NPRM,* both claimed in 2006 that the adopted rule modifications would limit the consortium exception's usefulness (and use) by preventing small entities that wished to be licensed as consortia from pooling their resources.

219. In its petition, NTCA declares that previously unavailable information—the results of a late fall 2005 survey that NTCA conducted of its members—led to NTCA's petition for reconsideration. According to NTCA, 62 percent of its survey respondents found it difficult to obtain financing for wireless projects, and 27 percent were concerned about their ability to obtain spectrum at auction. The Commission rejects this position, however, because NTCA does not connect the survey to its concern with the consortium exception. Indeed, neither NTCA nor the NTCA 2005 Wireless Survey Report indicates that the survey, conducted several months after the Commission sought comment on possible changes to the consortium exception, considered the consortium exception.

220. Blooston Rural states that it did not comment in 2005 on possible changes to the consortium exception, because the effect of the changes put out for comment was unclear. Blooston Rural also complains that the import of the possible modifications was obscured by the fact that they were part of a rulemaking focused on CSEA matters. Blooston Rural argues further that the Commission did not make clear that a licensee comprising consortium members would have to meet the designated entity financial caps. It contends that the Commission's clarification regarding the consortium exception with respect to the secondary market was not put out for comment in the *CSEA and Competitive Bidding NPRM* and is ''contrary to prior statements and practices of the Commission in dealing with small business consortia.'' Finally, Blooston Rural submits that notice of all consortium exception rule changes was inadequate because the Commission did not provide text of the proposed rule.

221. The Commission concludes that these objections are without merit. The *CSEA and Competitive Bidding NPRM* addressed non-CSEA matters at least as much as it did matters concerning the CSEA. A separate section of the non-CSEA portion of the item, identified as such in the table of contents, dealt solely with possible changes to the consortium exception. Moreover, the Commission articulated in the *CSEA and Competitive Bidding NPRM* all of the primary elements of the rule changes ultimately adopted. The Commission sought comment, for example, on whether it ''should adopt a new requirement that each member of the consortium file an individual long-form application for its respective, mutually agreed-upon license(s), following an auction in which a consortium has won one or more licenses,'' explaining that, ''[t]o comply with this requirement, consortium members would, prior to filing their short-form application, have reached an agreement as to how they would allocate among themselves any licenses (or disaggregated or partitioned portions of licenses) they might win.''

222. Blooston Rural also claims that the Commission's NPRM did not articulate what would happen to a consortium at the licensing stage. The Commission disagrees. The Commission sought comment on ''whether, in order for two or more consortium members to be licensed together for the same license(s) (or disaggregated or partitioned portions thereof), they should be required to form a legal business entity, such as a corporation, partnership, or limited liability company, after having disclosed this

intention on their short-form and long-form applications.'' In particular, the Commission asked for comment on ''whether such new entities would have to meet [the] small business or entrepreneur financial limits and whether allowing these entities to exceed the limits would be consistent with [the] existing designated entity and broadband PCS entrepreneur rules, as well as [the Commission's] obligations under the Communications Act.''

223. Thus the notice was sufficient to apprise even a casual reader of all the specific rule changes ultimately adopted. Further, notwithstanding Blooston Rural's intimations otherwise, there is no requirement in the Administrative Procedure Act (APA) that the specific wording of a proposed rule be provided in the notice. Rather, an agency must notify the public of ''either the terms or substance of the proposed rule or a description of the subjects and issues involved.'' 5 U.S.C. 553(b)(3). Accordingly, the consortium exception provisions put out for comment in the *CSEA and Competitive Bidding NPRM* fulfilled the notice requirements of the APA.

224. Addressing Blooston Rural's procedural and substantive objection to the Commission's clarification that the consortium exception does not apply in secondary market transactions, the Commission concludes that the clarification was an interpretive rule and thus exempt from APA notice requirements. 5 U.S.C. 553(b)(3)(A); *see also Perez* v. *Mortgage Bankers Ass'n.,* 135 S. Ct. 1199, 1204 & n.1 (2015). As modified, the consortium exception provides a benefit beginning with the short-form filing and continuing throughout the course of an auction to facilitate the pooling of resources for auction preparation and bidding. Given that participants in secondary market transactions are, by definition, not engaged in auction preparation or bidding, there is no rationale for assignees, transferees, or spectrum lessees (or their assignors, transferors, or spectrum lessors) to use the exception. And, while Blooston Rural claims that this clarification is contrary to prior Commission statements and practices, it provides no examples to support the claim. Accordingly, the clarification will stand.

225. The Commission also finds the petitioners' substantive objections to the primary rule modifications to be without merit. Both Blooston Rural and NTCA argue that the rule changes will reduce use of the consortium exception, contrary to the statutory mandate that the Commission promote the involvement of small businesses in the provision of spectrum-based services. NTCA contends, moreover, that under the modified exception small businesses will find spectrum financing more difficult than before, because they will not be able to ''pool their resources and enhance the value of their bidding credits.''

226. Petitioners' unsubstantiated claims have not convinced the Commission that the 2006 clarifications to the consortium exception have either limited its proper use—*i.e.,* to facilitate the pooling of resources for auction preparation and bidding—or negatively affected spectrum financing for small businesses. The consortium exception was so rarely employed before the 2006 rule changes took effect that any benefit from its prior use should, at best, be characterized as negligible. In the absence of evidence to the contrary, the Commission continues to believe that the rule changes have not adversely affected small businesses and that the changes instead prevent many of the structural and contractual pitfalls to which members of a consortium lacking a legally enforceable organizational structure could be vulnerable, particularly should any members file for bankruptcy protection.

227. Equally important, the modifications to the consortium exception strengthen the Commission's ability to enforce its rules by allowing it to identify and maintain legal access to those parties receiving license grants. The result is more efficient regulation, which ultimately benefits both licensees and the public. The Commission also finds that the rule modifications help ensure that small businesses and now rural service providers are not able to use the consortium exception as a means of evading the requirements for designated entity eligibility. The Commission therefore affirms its 2006 *CSEA and Competitive Bidding Report and Order* rule modifications to the consortium exception to the attribution rules for determining an applicant's eligibility for small business bidding credits.

V. Third Order on Reconsideration of the Second Report and Order in WT Docket No. 05–211

228. In the *Third Order on Reconsideration of the DE Second Report and Order,* the Commission resolves two remaining petitions for reconsideration received in response to the 2006 *DE Second Report and Order,* the Blooston Rural June 2, 2006 Petition and the Cook Inlet June 5, 2006 Petition. The Commission dismisses the Blooston Rural June 2, 2006 Petition because all of the issues raised in that petition were either resolved in 2010 by the Third Circuit's *Council Tree* decision or have been rendered moot by other adopted rule changes. In the interest of thoroughness, however, the Commission nonetheless provide the clarification requested by Cook Inlet.

229. *Background.* As detailed in its *Part 1 NPRM,* in its 2006 *DE Second Report and Order,* the Commission adopted two bright-line ''material relationship'' attribution rules—the AMR rule and the ''impermissible material relationship'' (IMR) rule—for the leasing or resale of spectrum held by designated entities. At the same time, the Commission lengthened the unjust enrichment period from five to ten years and adopted new DE reporting requirements, including an annual reporting requirement, to ensure compliance with its rules and policies.

230. The Commission received three petitions for reconsideration of the *DE Second Report and Order,* one opposition to the petitions, and one reply to the opposition. Council Tree, the Minority Media Telecommunications Council, and Bethel Native Corporation (collectively, the ''Joint Petitioners'') together filed a petition for expedited reconsideration before the Commission adopted, on its own motion, on June 1, 2006, the *Order on Reconsideration of the DE Second Report and Order,* 71 FR 34272, June 14, 2006. The Blooston Rural June 2, 2006 Petition and the Cook Inlet June 5, 2006 Petition were received by the Commission after its adoption of the *Order on Reconsideration of the DE Second Report and Order.*

231. The Commission addressed many of the arguments raised in these filings in the *Order on Reconsideration of the DE Second Report and Order.* The Commission denied the petition filed by the Joint Petitioners in the DE Second Order on Reconsideration of the Second Report and Order. Other arguments were subsequently resolved by the litigation initiated by the Joint Petitioners against the Commission in the United States Court of Appeals for the Third Circuit. The litigation culminated in 2010 with the Third Circuit's *Council Tree* decision in which the court vacated the IMR rule and the ten-year unjust enrichment period, holding that both provisions had been adopted with insufficient notice and opportunity for comment under the APA. While the court upheld the AMR rule the Commission has eliminated it. The Commission has also addressed objections to the annual DE reporting requirement and resolved the relevant aspect of Blooston Rural's June 2, 2006 Petition accordingly.

232. *Discussion.* With respect to the arguments that were still pending from the Blooston Rural June 2, 2006 Petition after the *Council Tree* decision, the Commission concludes that the actions it takes in this *Part 1 Report and Order* render these remaining arguments moot. In particular, the Blooston Rural June 2, 2006 Petition raised objections to the adequacy of notice and opportunity for comment on the Commission's AMR rule, as well as certain substantive objections about the rules' effectiveness. Further, Blooston Rural objected to aspects of the DE annual reporting requirement. Because the Commission has eliminated the AMR rule in the *Part 1 Report and Order,* Blooston Rural's June 2, 2006 objections to the rule are now moot.

233. Blooston Rural also objected to the DE annual reporting requirement. It criticized the rule on two bases: first, that the rule was unduly burdensome in that licensees with multiple auction licenses, each having a different grant date, would have to file multiple annual reports numerous times per year, and, second, that the requirement was duplicative of the DE reporting requirements of other Commission rules. The Commission has retained the annual DE reporting requirement, finding that it does not duplicate any of its other DE reporting requirements and continues to serve an important purpose, particularly in light of the additional flexibility it is affording DEs. Thus, the Commission denies Blooston Rural's request that it eliminate the requirement. Nevertheless, the Commission concludes that, while it has not repealed the annual DE reporting requirement, the Commission has eliminated any basis for Blooston Rural's objections to complying with the rule. For example, the Commission has greatly reduced the burden on DEs by modifying the annual reporting requirement to give all filers the same deadline for all licenses of September 30 of each calendar year. The Commission has further reduced the filing burden on DEs, and eliminated any redundancy caused by the annual reporting requirement, by clarifying that filers need not report agreements and arrangements otherwise required to be reported under 47 CFR 1.2110(n), so long as the current information is already on file in ULS and the filers provide in their annual reports the applicable ULS file number and filing date of the report containing the current information. Thus, the Commission concludes that, insofar Blooston Rural's June 2, 2006 Petition addresses the annual DE reporting requirement, it is, in part, denied and is otherwise moot.

234. The Cook Inlet June 5, 2006 Petition, in contrast, maintained that an issue raised in the Commission's *Order on Reconsideration of the DE Second Report and Order* required further clarification. Cook Inlet asserted that the consideration of DE status in the context of an assignment or transfer is unfair and discourages DEs from participating in the secondary market.

235. Simply stated, the Commission did not previously, and will not as a result of any of its rule changes, evaluate the eligibility of a DE for benefits when that DE is a transferor or assignor in a secondary market transaction. Instead, in the context of such transactions, the Commission evaluates the eligibility, if any, of the transferee or assignee of a license. Accordingly, the Commission concludes that Cook Inlet's arguments concerning retroactive consideration of DE status and 47 CFR 309(j)(3)(E)(ii) are without foundation.

VI. Third Report and Order in WT Docket No. 05–211

236. Finally, in this *DE Third Report and Order,* the Commission terminates consideration of proposals issued in a 2006 *DE Second Further Notice of Proposed Rule Making (DE Second FNPRM),* 71 FR 50379, August 25, 2006, in which it asked whether it should adopt any additional small business eligibility rules. The majority of commenters responding to the *DE Second FNPRM* opposed any additional modification of the DE eligibility requirements. The Commission concludes that this inquiry has been overtaken by the significant passage of time, the litigation regarding the rules adopted in the *DE Second Report and Order,* and its efforts to amend the Part 1 competitive bidding rules. Moreover, there was no record support for any of the changes the Commission was considering. The Commission therefore declines to adopt any of the proposals raised in the 2006 *DE Second FNPRM.*

237. Background. The *DE Second FNPRM* sought comment on additional proposals for eligibility restrictions on the relationships of DEs with certain other entities. In particular, the Commission sought comment on whether additional eligibility restrictions should apply to the relationships of DEs with members of a certain entity class or classes, the use of a financial threshold to define the class of entity triggering such restrictions, applying a particular spectrum interest type to define an entity class, and the possible adoption of an in-region component for the definition of relationships that should be subject to further eligibility restrictions.

238. In addition to these class-based restrictions, the Commission sought comment on whether it should adopt additional rule changes restricting the award of small business benefits under certain circumstances and in connection with relationships with certain entities. The Commission also requested comment on whether the relationships between DE applicants, or licensees, and other entities should be treated differently depending on the nature of the specific entity and the surrounding circumstances. The Commission further sought comment on the adoption of a personal net worth test for DE eligibility determinations.

239. Ten parties filed comments in response to the *DE Second FNPRM,* and five parties filed reply comments. The majority of commenters argued that the Commission should not adopt any further measures beyond the then-newly revised 2006 rules.

240. *Discussion.* The Commission concludes that it will not adopt any designated entity eligibility rules based on the record acquired in the *DE Second FNPRM,* and the Commission hereby closes that inquiry. In the *DE Second FNPRM,* the Commission requested guidance on whether it ''should adopt additional rule changes that would restrict the award of designated entity benefits'' in certain circumstances and for relationships with certain types of entities. The Commission also sought comment on the possible use of a personal net worth test in determinations of DE eligibility, citing a proposal to restrict individuals with a net worth of $3 million or more from having a controlling interest in a designated entity.

241. Commenters offered limited support for additional eligibility restrictions based upon the possibility of adopting further restrictions related to class type and/or financial and operational agreements. Most commenters, including Council Tree, the original proponent of the rule changes, urged the Commission to refrain from adopting additional eligibility restrictions based on the relationships of a designated entity applicant or licensee with a particular class of entities. Most commenters also responded negatively to the potential use of an in-region component in any further material relationship restrictions. The record compiled in 2006 therefore indicated little support for the adoption of any additional restrictions such as those contemplated

in the *DE Second FNPRM,* and provides no basis upon which to adopt rules.

242. Similarly, no commenter, including Council Tree, the original proponent of a personal net worth test, supported the adoption of such a restriction. Several commenters in 2006 argued strongly that a personal net worth test would be unnecessary and ineffective. The Commission therefore concludes that the widespread opposition to such a restriction reinforces the Commission's previous conclusions on this matter. The Commission has previously observed that personal net worth limits can be difficult to apply and to enforce. Accordingly, the Commission declines to adopt any personal net worth test for determining small business eligibility.

243. In light of the many policy and rule modifications the Commission adopts regarding designated entity eligibility, as well as the general lack of support by commenters, the Commission closes the record compiled in response to the 2006 *DE Second FNPRM,* and terminates the inquiry.

VII. Procedural Matters

A. Delegation To Correct Rules.

244. The Commission delegates authority to the Wireless Telecommunications Bureau, as appropriate, to make corrections to the rules set forth in Appendix A as necessary to conform them to the text of the *Part 1 Report and Order.* The Commission notes that any entity that disagrees with a rule correction made on delegated authority will have the opportunity to file an Application for Review by the full Commission.

B. Final Regulatory Flexibility Act Analysis

245. As required by the Regulatory Flexibility Act of 1980, as amended (RFA), the Commission has prepared this Final Regulatory Flexibility Analysis (FRFA) of the possible significant economic impact on small entities by the policies and rules adopted in the *Part 1 Report and Order.* The Commission will send a copy of the *Part 1 Report and Order,* including this FRFA, to the Chief Counsel for Advocacy of the Small Business Administration (''SBA''). In addition, the *Part 1 Report and Order* and the FRFA (or summaries thereof) will be published in the **Federal Register**.

246. As required by the RFA, an Initial Regulatory Flexibility Analysis (IRFA) was incorporated in the *NPRM* and a Supplemental Initial Regulatory Flexibility Analysis (''Supplemental IRFA) was incorporated in the *Part 1 PN.* The Commission sought written public comment on the proposals in the *NPRM* and *Part 1 PN,* including comment on the IRFA and Supplemental IRFA. The Commission received one written *ex parte* letter addressing the IRFA or Supplemental IRFA. The Office of Advocacy, U.S. Small Business Administration (SBA Office of Advocacy) supports the Commission's repeal of the attributable material relationship (AMR) rule and its decision allowing small businesses, rural telephone companies, and businesses owned by members of minority groups and women more flexibility in their ability to lease spectrum. The SBA Office of Advocacy argues against ''arbitrary caps'' on DEs, saying that such caps would limit a small business's ability to grow. It also warns against expanding the DE program to include some large businesses, explaining that large businesses do not need another advantage over small entities. Because the Commission amends the rules in the *Part 1 Report and Order* it has included this FRFA which conforms to the RFA.

A. Need for, and Objectives of, the Order

247. Given the prolific changes witnessed in the wireless industry over the last decade, this *Part 1 Report and Order* adopts revisions to certain of the Part 1 competitive bidding rules in advance of an auction that holds historic potential for interested applicants to acquire licenses for below 1–GHz spectrum in the Broadcast Television Spectrum Incentive Auction (Incentive Auction). The *Part 1 Report and Order* therefore reforms some of the Commission's general Part 1 rules governing competitive bidding for spectrum licenses to reflect changes in the marketplace, including the challenges faced by new entrants. The *Part 1 Report and Order* new rules also advance the statutory directive to ensure that designated entities are given the opportunity to participate in the provision of spectrum-based services while preventing unjust enrichment, and fulfill the commitment made in the *Incentive Auction R&O.* Together these revisions will assure that the Commission's part 1 rules continue to promote the Commission's fundamental statutory objectives.

248. Specifically, the *Part 1 Report and Order* adopts revisions that: (1) Modify its eligibility requirements for small business benefits, and update the standardized schedule of small business sizes, including the gross revenues thresholds used to determine eligibility; (2) establish a new bidding credit for eligible rural service providers; (3) implement a cap on the overall amount of bidding credits available for eligible designated entities in any one auction; (4) strengthen and target attribution rules to prevent the unjust enrichment of ineligible entities; (5) modify its DE reporting requirements; (6) revise the former defaulter rule, consistent with the waiver the Commission granted in Auction 97; (7) adopt rules prohibiting joint bidding arrangements with limited exceptions, and make related updates to its rule on prohibited communications; and (8) adopt rules prohibiting the same individual or entity as well as entities that have controlling interests in common from becoming qualified to bid on the basis of more than one short-form application in a specific auction, with a limited exception for certain rural wireless partnerships and individual members of such partnerships.

249. The *Part 1 Report and Order* also resolves long standing petitions for reconsideration and adopts necessary clean up revisions to the Commission's Part 1 competitive bidding rules.

250. With respect to small businesses, the *Part 1 Report and Order's* revisions to the Commission's rules reflect that small businesses need greater opportunities to gain access to capital so that they may have an opportunity to participate in the provision of spectrum-based services in today's communications marketplace. In the past decade, the rapid adoption of smartphones and tablet computers and the widespread use of mobile applications, combined with the increasing deployment of high-speed 3G and now 4G technologies, have driven significantly more intensive use of mobile networks. This progression from the provision of mobile voice services to the provision of mobile broadband services has increased the need for access to spectrum. In addition, in the past decade, the number of small and regional mobile wireless service providers has significantly decreased, yet regional and local service providers continue to offer consumers additional choices in the areas they serve. The Commission anticipates that by revising its rules to allow small businesses to take advantage of the same opportunities to utilize their spectrum capacity and gain access to capital as those afforded to larger licensees, it can better achieve its statutory directives. Nonetheless, the Commission remains mindful of its obligation to prevent unjust enrichment of ineligible entities.

B. Legal Basis

251. The action is authorized under sections 1, 4(i), 303(r), 309(j), and 316 of

the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), 309(j), and 316.

C. Summary of Significant Issues Raised by Public Comments in Response to the IFRA or Supplemental IFRA

252. No commenters directly responded to the IRFA or Supplemental IRFA. The SBA Office of Advocacy raised concerns regarding the analysis contained within the earlier IRFAs. Having reviewed both the initial IRFA and the supplemental IRFA the Commission concludes that the analyses satisfy the requirements of 5 U.S.C. 603, as further specified in 5 U.S.C. 607. The IRFAs sufficiently describe the impact of the rules the Commission proposed. The Commission provides further detail in this FRFA below on the impact of the rules the Commission adopts in this order, the steps the Commission has taken to minimize the significant economic impact on small entities consistent with the stated objectives of the Communications Act, and an analysis of why these rules were adopted herein and other significant alternatives that were considered and rejected. Additionally, a number of commenters raised concerns about the impact on small businesses of various auction-related issues. The Commission has nonetheless addressed these concerns in the FRFA.

D. Description and Estimate of the Number of Small Entities to Which the Rules Will Apply

253. 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. The RFA generally defines the term ''small entity'' as having the same meaning as the terms ''small business,'' ''small organization,'' and ''small government jurisdiction.'' In addition, the term ''small business'' has the same meaning as the term ''small business concern'' under the Small Business Act. 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 SBA.

254. *Small Businesses, Small Organizations, and Small Governmental Jurisdictions.* The *Part 1 Report and Order's* revisions may, over time, affect small entities that are not easily categorized at present. The Commission therefore describes here, at the outset, three comprehensive, statutory small entity size standards. First, nationwide, there are a total of approximately 28.2 million small businesses, according to the SBA. In addition, a ''small organization'' is generally ''any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.'' Nationwide, as of 2007, there were approximately 1,621,315 small organizations. Finally, the term ''small governmental jurisdiction'' is defined generally as ''governments of cities, towns, townships, villages, school districts, or special districts, with a population of less than fifty thousand.'' Census Bureau data for 2011 indicate that there were 89,476 local governmental jurisdictions in the United States. The Commission estimates that, of this total, as many as 88,506 entities may qualify as ''small governmental jurisdictions.'' Thus, the Commission estimates that most governmental jurisdictions are small.

255. *Licenses Assigned by Auction.* The changes and additions to the Commission's rules in the *Part 1 Report and Order* are of general applicability to all auctionable services. Accordingly, this FRFA provides a general analysis of the impact of the proposals on small businesses rather than a service-by-service analysis. The number of entities that may apply to participate in future Commission spectrum auctions is unknown. Moreover, the number of small businesses that have participated in prior spectrum auctions has varied. As a general matter, the number of winning bidders that qualify as small businesses at the close of an auction does not necessarily represent the number of small businesses currently in service. Also, the Commission does not generally track subsequent business size unless, in the context of changes in control, or assignments or transfers, unjust enrichment issues are implicated.

256. *Wireless Telecommunications Carriers (except satellite).* The Census Bureau defines this category to include ''establishments engaged in operating and maintaining switching and transmission facilities to provide communications via the airwaves. Establishments in this industry have spectrum licenses and provide services using that spectrum, such as cellular phone services, paging services, wireless Internet access, and wireless video services.'' The SBA has developed a small business size standard for Wireless Telecommunications Carriers (except satellite). Under the SBA's standard, a business is small if it has 1,500 or fewer employees. For this category, Census data for 2007 show that there were 1,383 firms that operated for the entire year. Of this total, 1,368 firms (approximately 99 percent) had employment of 999 or fewer employees and only 15 (approximately 1 percent) had employment of 1,000 employees or more. Similarly, according to Commission data, 413 carriers reported that they were engaged in the provisions of wireless telephony, including cellular service, PCS, and Specialized Mobile Radio (SMR) Telephony services. Of these, an estimated 261 have 1,500 or fewer employees and 152 have more than 1,500 employees. Consequently, the Commission estimates that approximately half or more of these firms can be considered small. Thus under this category and the associated small business size standard, the Commission estimates that the majority of wireless telecommunications carriers (except satellite) are small entities that may be affected by the NPRM's proposed actions.

257. *Broadband Radio Service and Educational Broadband Service.* Broadband Radio Service systems, previously referred to as Multipoint Distribution Service (MDS) and Multichannel Multipoint Distribution Service (MMDS) systems, and ''wireless cable,'' transmit video programming to subscribers and provide two-way high speed data operations using the microwave frequencies of the Broadband Radio Service (BRS) and Educational Broadband Service (EBS) (previously referred to as the Instructional Television Fixed Service (ITFS)). In connection with the 1996 BRS auction, the Commission established a small business size standard as an entity that had annual average gross revenues of no more than $40 million in the previous three calendar years. The BRS auction resulted in 67 successful bidders obtaining licensing opportunities for 493 Basic Trading Areas (BTAs). Of the 67 auction winners, 61 met the definition of a small business. BRS also includes licensees of stations authorized prior to the auction. At this time, based on its review of licensing records, the Commission estimates that of the 61 small business BRS auction winners, 48 remain small business licensees. In addition to the 48 small businesses that hold BTA authorizations, there are approximately 86 incumbent BRS licensees that are considered small entities (18 incumbent BRS licensees do not meet the small business size standard). After adding the number of small business auction licensees to the number of incumbent licensees not already counted, there are currently approximately 133 BRS licensees that are defined as small businesses under either the SBA or the Commission's rules. In 2009, the Commission

conducted Auction 86, the sale of 78 licenses in the BRS areas. The Commission established three small business size standards that were used in Auction 86: (i) An entity with attributed average annual gross revenues that exceeded $15 million and do not exceed $40 million for the preceding three years was considered a small business; (ii) an entity with attributed average annual gross revenues that exceeded $3 million and did not exceed $15 million for the preceding three years was considered a very small business; and (iii) an entity with attributed average annual gross revenues that did not exceed $3 million for the preceding three years was considered an entrepreneur. Auction 86 concluded in 2009 with the sale of 61 licenses. Of the 10 winning bidders, two bidders that claimed small business status won four licenses; one bidder that claimed very small business status won three licenses; and two bidders that claimed entrepreneur status won six licenses. The Commission notes that, as a general matter, the number of winning bidders that qualify as small businesses at the close of an auction does not necessarily represent the number of small businesses currently in service.

258. In addition, the SBA's placement of Cable Television Distribution Services in the category of Wired Telecommunications Carriers is applicable to cable-based educational broadcasting services. Since 2007, Wired Telecommunications Carriers have been 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.'' Establishments in this industry use the wired telecommunications network facilities that they operate to provide a variety of services, such as wired telephony services, including VoIP services; wired (cable) audio and video programming distribution; and wired broadband Internet services. By exception, establishments providing satellite television distribution services using facilities and infrastructure that they operate are included in this industry. The SBA has developed a small business size standard for this category, which is: All such firms having 1,500 or fewer employees. Census data for 2007 shows that there were 3,188 firms that operated for the duration of that year. Of those, 3,144 had fewer than 1,000 employees, and 44 firms had more than 1,000 employees. Thus under this category and the associated small business size standard, the majority of such firms can be considered small. In addition to Census data, the Commission's Universal Licensing System indicates that as of July 2014, there are 2,006 active EBS licenses. The Commission estimates that of these 2,006 licenses, the majority are held by non-profit educational institutions and school districts, which are by statute defined as small businesses.

259. *Television Broadcasting.* This economic census category ''comprises establishments primarily engaged in broadcasting images together with sound. These establishments operate television broadcasting studios and facilities for the programming and transmission of programs to the public.'' The SBA has created the following small business size standard for Television Broadcasting firms: Those having $38.5 million or less in annual receipts. The Commission has estimated the number of licensed commercial television stations to be 1,387. In addition, according to Commission staff review of the BIA/Kelsey, LLC's *Media Access Pro Television Database* on July 30, 2014, about 1,276 of an estimated 1,387 commercial television stations (or approximately 92 percent) had revenues of $38.5 million or less. The Commission therefore estimates that the majority of commercial television broadcasters are small entities.

260. The Commission notes, however, that in assessing whether a business concern qualifies as small under the above definition, business (control) affiliations must be included. Its estimate, therefore, likely overstates the number of small entities that might be affected by the *Part 1 Report and Order's* rules because the revenue figure on which it is based does not include or aggregate revenues from affiliated companies. In addition, an element of the definition of ''small business'' is that the entity not be dominant in its field of operation. The Commission is 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 does not exclude any television station from the definition of a small business on this basis and is therefore possibly over-inclusive to that extent.

261. In addition, the Commission has estimated the number of licensed noncommercial educational television stations to be 395. These stations are non-profit, and therefore considered to be small entities.

262. There are also 2,460 LPTV stations, including Class A stations, and 3,838 TV translator stations. Given the nature of these services, the Commission will presume that all of these entities qualify as small entities under the above SBA small business size standard.

263. *Radio Broadcasting.* The SBA defines a radio broadcast station as a small business if such station has no more than $38.5 million in annual receipts. Business concerns included in this industry are those ''primarily engaged in broadcasting aural programs by radio to the public.'' According to review of the BIA/Kelsey, LLC's *Media Access Pro Radio Database* as of July 30, 2014, about 11,332 (or about 99.9 percent) of 11,343 commercial radio stations have revenues of $38.5 million or less and thus qualify as small entities under the SBA definition. The Commission notes, however, that, in assessing whether a business concern qualifies as small under the above definition, business (control) affiliations must be included. This estimate, therefore, likely overstates the number of small entities that might be affected, because the revenue figure on which it is based does not include or aggregate revenues from affiliated companies.

264. *Cable and Other Subscription Programming.* This industry comprises establishments primarily engaged in operating studios and facilities for the broadcasting of programs on a subscription or fee basis. The broadcast programming is typically narrowcast in nature (*e.g.,* limited format, such as news, sports, education, or youth-oriented). These establishments produce programming in their own facilities or acquire programming from external sources. The programming material is usually delivered to a third party, such as cable systems or direct-to-home satellite systems, for transmission to viewers. Since 2007, the prior but now discontinued service involving distribution of programming via cable television was placed within the broad economic census category of Wired Telecommunications Carriers. The SBA has developed a small business size standard for this category, which consists of all such firms with gross annual receipts of 38.5 million dollars or less. Census data for 2007, when data about Wired Telecommunications Carriers were used for Cable and Other Program Distribution, show that there were 3,188 Wired Telecommunications Carrier firms that operated for the entire year. Of this total, 3,144 had fewer than 1,000 employees. Thus under this size

standard, the majority of firms offering cable and other subscription programming can be considered small.

265. In addition, an element of the definition of ''small business'' is that the entity not be dominant in its field of operation. The Commission is unable at this time to define or quantify the criteria that would establish whether a specific radio station is dominant in its field of operation. Accordingly, the estimate of small businesses to which rules may apply does not exclude any radio station from the definition of a small business on this basis and therefore may be 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. The Commission notes that it is difficult at times to assess these criteria in the context of media entities and the estimates of small businesses to which they apply may be over-inclusive to this extent.

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

266. The updated reporting, recordkeeping, and other compliance requirements resulting from the *Part 1 Report and Order* will apply to all entities in the same manner. The Commission believes that these rules assist it meeting its statutory goals by providing DEs more flexibility in finding the capital needed for acquisition and provisions of spectrum-based services while ensuring that designated entity benefits go to bona fide small businesses and eligible rural service providers. The Commission does not believe that the costs and/or administrative burdens associated with the rules will unduly burden small entities. The *Part 1 Report and Order* makes a number of rule changes that will affect reporting, recordkeeping, and other compliance requirements. Each of these changes is described below.

267. *Eligibility for Bidding Credits.* The *Part 1 Report and Order* makes changes to the Commission's process for evaluating small business eligibility for bidding credits. In particular, the *Part 1 Report and Order* repeals the AMR rule and replaces it with a more flexible approach under which the Commission would evaluate small business eligibility on a license-by-license basis, using a two-pronged test. The first prong would evaluate whether an applicant meets the applicable small business size standard and is therefore eligible for benefits. To evaluate small business eligibility, the *Part 1 Report and Order* applies the Commission's existing controlling interest standard and affiliation rules to determine whether an entity should be attributable based on whether that entity has *de jure* or *de facto* control of, or is affiliated with, the applicant's overall business venture. Once the first prong has been met, the Commission would evaluate eligibility under the second prong. Under the second prong, the *Part 1 Report and Order* determines an entity's eligibility to retain small business benefits on a license-by-license basis, based on whether it has maintained *de jure* and *de facto* control of the license. Under this license-by-license approach, an entity will not necessarily lose its eligibility for all current and future small business benefits solely because of a decision associated with any particular license. Instead, while a small business might incur unjust enrichment obligations if it relinquishes *de jure* or *de facto* control of any particular license for which it claimed benefits, so long as the revenues of its attributable interest holders (*i.e.,* the DE's affiliates, its controlling interests, and the affiliates of its controlling interests) continue to qualify under the relevant small business size standard, it could still retain its eligibility to retain current and future benefits on existing and future licenses. The *Part 1 Report and Order* determines, on the basis of the express language of section 309(j), that there is no statutory requirement for DEs to directly provide primarily facilities-based service to the public with each license.

268. The *Part 1 Report and Order* also modifies the Commission's secondary market rules to comport with the Commission's proposed approach to assessing small business eligibility. Specifically, the *Part 1 Report and Order* amends the language in 47 CFR 1.9020(d)(4) to remove the conflicting reference to the control standard of 47 CFR 1.2110 in order to make clear that small business lessors are fully subject to the same *de facto* control standard for spectrum manager leasing that applies to all other licensees. This modification should clarify that 47 CFR 1.9010 alone defines whether a licensee, including a small business, retains *de facto* control of the spectrum that it leases to a spectrum lessee in the context of spectrum manager leasing.

269. *Attribution Rules.* The *Part 1 Report and Order* adopts an additional attribution requirement under which, during the five-year unjust enrichment period, the gross revenues (or the subscribers in the case of a rural service provider) of a disclosable interest holder in a DE applicant or licensee will become attributable, on a license-by-license basis, for any license in which the disclosable interest holder uses, in any manner, more than 25 percent of the spectrum capacity of a DE's license awarded with bidding credits. Under this rule, a disclosable interest holder is defined as any party holding a ten percent or greater interest of any kind in the DE, including but not limited to, a ten percent or greater interest in any class of stock, warrants, options or debt securities in the applicant or licensee. However, for DEs that acquire licenses with the new rural service provider bidding credit, this new attribution rule will not apply to any disclosable interest holder that would independently qualify for a rural service provider bidding credit.

270. The *Part 1 Report and Order* declines to make any adjustments to the Commission's unjust enrichment rules and applies these rules to the new rural service provider bidding credit.

271. *Bidding Credits.* The *Part 1 Report and Order* refines the primary way that the Commission facilitates participation by small businesses at auction through its bidding credit program. Bidding credits operate as a percentage discount on the winning bid amounts of a qualifying small business. By making the acquisition of spectrum licenses more affordable for new and existing small businesses, bidding credits facilitate their access to needed capital. The Commission establishes eligibility for bidding credits for each auctionable service, adopting one or more definitions of the small businesses that will be eligible. The Commission's small business definitions have been based on an applicant's average annual gross revenues over a three-year period. The *Part 1 Report and Order* retains the existing three-tiered schedule for determining eligibility for bidding credits but utilizes the GDP price index to increase the general schedule of size standards in its part 1 rules, measured by gross revenues, for purposes of determining an entity's eligibility for a bidding preference. Specifically, the *Part 1 Report and Order* revises the standardized schedule in 47 CFR 1.2110(f) as follows: (1) Businesses with average annual gross revenues for the preceding three years not exceeding $4 million would be eligible for a 35 percent bidding credit; (2) Businesses with average annual gross revenues for the preceding three years not exceeding $20 million would be eligible for a 25 percent bidding credit; and (3) Businesses with average annual gross revenues for the preceding three years not exceeding $55 million would be eligible for a 15 percent bidding credit.

272. The rules adopted in the *Part 1 Report and Order* will apply to the 600 MHz band spectrum licenses to be offered in the Incentive Auction and all Commission auctions in which the short-form deadline falls on or after the release date of the *Part 1 Report and Order.* In the Incentive Auction proceeding, the Commission adopted a 15 percent bidding credit for small businesses (defined as entities with average annual gross revenues for the preceding three years not exceeding $40 million) and a 25 percent bidding credit for very small businesses (defined as entities with average annual gross revenues for the preceding three years not exceeding $15 million). Accordingly, the *Part 1 Report and Order* adopts for the 600 MHz band increases in the gross revenues thresholds associated with the 25 percent and 15 percent bidding credits that are consistent with the increased gross revenues thresholds in the *Part 1 Report and Order* for the standardized schedule in its part 1 competitive bidding rules.

273. The *Part 1 Report and Order* adopts a 15 percent bidding credit for qualifying service providers that provide commercial communications services to a customer base of fewer than 250,000 combined wireless, wireline, broadband, and cable subscribers and serve primarily rural areas. To determine whether a provider has fewer than 250,000 combined subscribers, the Commission will attribute the subscribers of all the provider's affiliates. The Commission will apply its existing definition of rural, a county with a population density of 100 persons or fewer per square mile. To qualify for a rural service provider bidding credit, an applicant must certify in its short-form application that it serves predominantly rural areas. An applicant will be permitted to claim a rural service provider bidding credit or a small business bidding credit, but not both.

274. The *Part 1 Report and Order* adopts a limit or cap on the total amount of that a small business or rural service provider can receive in any particular auction, to be determined on an auction-by-auction basis. Specifically, the *Part 1 Report and Order* establishes a cap floor for any particular auction at $25 million for each eligible small business, and $10 million for each eligible rural service provider. Additionally, the *Part 1 Report and Order* sets the caps for the upcoming incentive auction at $150 million for a small business and $10 million for a rural service provider. For markets with a population of 500,000 or less, a DE bidder may not receive more than $10 million in bidding credits. To the extent a small business does not claim the full $10 million in bidding credits in the smaller markets, it may apply the remaining balance to its winning bids on larger licenses, up to the aggregate $150 million cap for small businesses.

275. *DE Reporting Requirements.* The *Part 1 Report and Order* modifies the DE annual reporting requirement in 47 CFR 1.2110(n) require that all annual reports be filed no later than September 30 of each calendar year, reflecting the status of each license subject to unjust enrichment requirements held by a particular licensee as of August 31 of that same calendar year. Any licensee required to file a report between the release date of the *Part 1 Report and Order* and the effective date of the amended rule may defer filing its annual report until September 30, 2016. The new rule only applies to licenses acquired with DE benefits and still held subject to unjust enrichment obligations. If a license is transferred from a DE to a DE, the licensee who holds the license on September 30 of that year is responsible for filing the annual report. The annual report does not need to list agreements and arrangements that otherwise are included in the report if the information has already been filed with the Commission and the information is current. Instead the filer must provide both the ULS file number of the report containing such information and the date that the report was filed. These new DE reporting requirements will be applied to the new rural service provider bidding credit.

276. *Former Defaulter Rule.* The *Part 1 Report and Order* adopts changes to the Commission's former defaulter rule to narrow the scope of the defaults and delinquencies that will be considered in determining whether or not an auction participant is a former defaulter. Specifically, the *Part 1 Report and Order* excludes any cured default on any Commission license or delinquency on any non-tax debt owed to any Federal agency for which any of the following criteria are met: (1) The notice of the final payment deadline or delinquency was received more than seven years before the relevant short-form application deadline; (2) the default or delinquency amounted to less than $100,000; (3) the default or delinquency was paid within two quarters (*i.e.,* 6 months) after receiving the notice of the final payment deadline or delinquency; or (4) the default or delinquency was the subject of a legal or arbitration proceeding that was cured upon resolution of the proceeding. This rule will be applied on a prospective basis, including for the Incentive Auction.

277. *Joint Bidding.* The *Part 1 Report and Order* prohibits joint bidding arrangements between nationwide providers and between nationwide and non-nationwide providers. The *Part 1 Report and Order* also prohibits joint bidding arrangements between non-nationwide providers who are separate auction applicants but allows the use of joint ventures and consortia. The *Part 1 Report and Order* defines ''joint bidding arrangements'' as arrangements that involve a shared strategy for bidding in auction. This definition does not include agreements that are solely operational in nature, like agreements for roaming and leasing, which continue to be permitted. The Commission are permitting non-nationwide providers to form consortia and joint ventures. However, the Commission specify that: (1) DEs can participate in only one consortium in an auction, which shall be the exclusive bidding vehicle for its members in that auction, and (2) non-nationwide providers may participate in an auction through only one joint venture, which also shall be the exclusive bidding vehicle for its members in that auction. The *Part 1 Report and Order* also adopts a rule prohibiting individuals from serving as an authorized bidder for more than one auction applicant. The *Part 1 Report and Order* adopts a rule requiring all applicants to certify that they are not, and will not be, privy to, or involved in, in any way the bids or bidding strategy of more than one auction applicant. An applicant is also allowed to certify that it has established internal controls to preclude any person serving as an agent or employee for an applicant from having information about the bids or bidding strategies of more than one applicant or communicating such information to either applicant. The *Part 1 Report and Order* modifies its prohibited communications rule to prohibit an applicant from communicating bids or bidding information with any other applicant or any nationwide provider but provides limited exceptions for any arrangements that are solely operational in nature and are disclosed on an applicant's short-form application.

278. *Commonly Controlled Entities.* The *Part 1 Report and Order* codifies an established competitive bidding procedure that prohibits the same individual or entity from filing more than one short-form application to participate in an auction. The *Part 1 Report and Order* also adopts a new rule

that would prevent entities that are controlled by a single individual or set of individuals from qualifying to bid on licenses in the same or overlapping geographic areas in a specific auction on more than one short-form application. The *Part 1 Report and Order* adopts a limited exception to this general prohibition for existing rural partnerships. Under this exception, a qualifying wireless partnership and their individual rural telephone company members will be permitted to participate separately in an auction. The *Part 1 Report and Order* defines ''controlling interest'' as individuals or entities with positive or negative *de jure* or *de facto* control of the licensee.

279. *Miscellaneous Part 1 Revisions.* In addition to changes that would implement the foregoing proposals, the *Part 1 Report and Order* amends two of the Commission's Part 1, Subpart Q, rules, 47 CFR 1.2111 and 1.2112.

280. The *Part 1 Report and Order* eliminates two provisions of 47 CFR 1.2111: (1) 47 CFR 1.2111(a), under which applicants for assignments or transfers during the first three years of a license term must provide the Commission with detailed contract and marketing information, and (2) 47 CFR 1.2111(b), a never-used unjust enrichment payment requirement for broadband PCS C and F block set-aside licenses.

281. The *Part 1 Report and Order* clarifies the auction application requirements for reporting an entity's percentage ownership in the applicant and in FCC-regulated entities under 47 CFR 1.2112. The *Part 1 Report and Order* further changes the rule to specify application requirements for bidding consortia. The *Part 1 Report and Order* also corrects two errors in the rule caused by the inadvertent substitution of an incorrect paragraph in the Code of Federal Regulations publication of the rule for the correct one published in the **Federal Register** summary of the DE Second Report and Order. The first error was the addition of a requirement that DE short-form applicants list and summarize all their agreements that support their DE eligibility, a requirement that the Commission intended to apply only to long-form applicants. The *Part 1 Report and Order* deletes the requirement with respect to the short-form. The second error was the deletion of a requirement that DE short-form applicants list the parties with which they have lease or resale arrangements for any of the DE applicants' spectrum. The *Part 1 Report and Order* reinstates this requirement.

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

282. 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.

283. The *Part 1 Report and Order* repeals the AMR rule and replaces it with a two-pronged analysis. This approach to evaluating attribution and establishing small business eligibility should provide small businesses with greater opportunities to participate in the provision of spectrum-based services. Moreover, insofar as the *Part 1 Report and Order* should allow small businesses greater flexibility to engage in business ventures that include increased forms of leasing and other spectrum use arrangements, the Commission anticipates that the combined intent of the updated rules should increase the potential sources of revenue for the small business and decrease the likelihood that it would be subject to undue influence by any particular user of a single license. The *Part 1 Report and Order's* two-pronged approach to establishing small business eligibility would also ensure that a licensee retains control of all licenses for which it seeks bidding credits, while providing greater flexibility for any acquired without such benefits. Further, the elimination of the AMR rule and clarification of how spectrum manager leasing rules apply to DEs should allow small businesses greater certainty to participate in secondary markets transactions.

284. The Commission's determination that section 309(j) does not require a DE to directly provide primarily facilities-based service to the public removes one barrier facing small businesses in providing spectrum-based services. The *Part 1 Report and Order* retains the focus of the facilities-based requirement, specifically to prevent unjust enrichment, by strengthening other aspects of its rules, like its attribution and unjust enrichment provisions. A facilities-based requirement would operate as an impediment, while the Commission's adjustments are narrowly tailored to better strike the balance between the Commission's statutory goals. In eliminating this requirement, DEs now have more flexibility in how they may utilize their licenses won with bidding credits.

285. The *Part 1 Report and Order's* new attribution rule is an additional safeguard to ensure that benefits are award only to eligible, *bona fide* entities. The Commission declines a number of alternative proposals focusing on restricting financing or agreements with large or regional carriers due to concerns that these proposals would impede a DE's ability to raise capital and gain operational experience. The Commission also declines proposals for an exception to its attribution rules for rural service provides who hold a minority interest in a cellular general partnership and to relax attribution rule in regards to immediate family members and of officers and directors. The Commission declines proposals to modify or eliminate its tribal exclusion to the attribution rule. The attribution rule is carefully tailored to ensure that DE benefits are not awarded to ineligible entities, while not being overly broad. The declined proposals would have affected the balance of the attribution rule, and in doing so, weaken the Commission's safeguards against the flow of DE benefits to ineligible entities.

286. The *Part 1 Report and Order* retains the Commission's three-tiered structure of small business bidding credits while increasing the gross revenues thresholds that define the three tiers of small businesses in the Part 1 schedule by which the Commission provides the corresponding available bidding credits would encourage small business participation in spectrum license auctions. The gross revenues thresholds, based on the GDP index, are intended to more accurately reflect what constitutes a ''small business'' in today's marketplace, taking into consideration the relative size of the large, national providers. This update to the thresholds will provide an economic benefit to small entities by making it easier to acquire spectrum licenses. The *Part 1 Report and Order* declines other bidding credit percentages proposed by commenters and the use of a MHz per pop methodology for setting thresholds at levels that would be over inclusive. It also declines proposals favoring a single bidding credit in lieu of the current three-tier system, and the creation of a new entrant bidding credit. The three-tiered system gives it flexibility to adjust the bidding credits available to reflect

the spectrum being offered at auction. Furthermore, the current percentages will enable those who qualify to compete in a Commission auction while not giving an unfair advantage against auction participants who do not qualify for a bidding credit.

287. The *Part 1 Report and Order's* new rural service provider bidding credit is designed to better enable rural service providers to compete for spectrum at auction and increase the availability of mobile voice and broadband services in rural areas. The new rural service provider bidding credit is 15 percent. The Commission rejected proposals for a 25 percent rural service provider bidding credit. The Commission believes that a bidding credit of 15 percent is the proper amount. While this new bidding credit will promote the provision of service in rural areas, many of the service providers that are eligible for the rural service provider bidding credit have well over $55 million in annual revenues and thus have far greater access to capital than most small businesses. The 15 percent bidding credit strikes the right balance between its existing DE system where rural providers are often unable to win a license covering their service areas limiting an unnecessary advantage received by an existing rural provider in certain markets. The Commission also declines the proposal to allow a winning bidder to deduct from its auction purchase price the *pro rata* value of any area partitioned to a rural telephone company, where the area includes all or a portion of the rural telephone company's service area. This proposal was declined because it would be overly burdensome and benefit those choosing not to serve rural areas. The Commission also declines proposals to make the small business and rural service provider bidding credits cumulative because cumulative bidding credits would provide an unnecessary advantage in certain markets.

288. The *Part 1 Report and Order* adopts bidding caps for the small business and rural service provider bidding credits. These caps will be determined for all future spectrum auctions on an auction-by-auction basis. The *Part 1 Report and Order* sets the cap floor for any particular auction at $25 million for the small business bidding credit and $10 million for the rural service provider bidding credit. The *Part 1 Report and Order* also set the bidding credit caps for the upcoming incentive auction at $150 million for the small business bidding credit and $10 million for the rural service provider bidding credit. Additionally, the *Part 1 Report and Order* limits the amount of bidding credits a bidder in the upcoming Incentive Auction may obtain to $10 million in markets with a population of 500,000 or less. If the full $10 million is not claimed, a bidder may apply its remaining balance to winning bids on larger licenses, up to $150 million. The Commission declines proposals advocating for no caps and for set caps of varying amounts. The caps will assist DEs by providing some level of assurance of bidding activity. Additionally, the caps will protect the integrity of the Commission's auction process by discouraging those who may try to game the DE system. While caps limit the amount of assistance a DE may receive, the Commission has the flexibility to calibrate the caps to the spectrum being offered in a particular auction. Based on past auction data, the *Part 1 Report and Order* adopts caps for the upcoming incentive auction. In the most recent auctions of CMRS spectrum, the $150 million cap would have allowed the vast majority of the bidding credits awarded to DEs. The 500,000 population threshold provides an easily administrable delineation between larger urban and smaller rural markets and the average population density for markets with a population of 500,000 or less roughly corresponds with its approach in defining rural areas. Additionally, a $10 million cap on the rural service provider bidding credit is the appropriate amount to stimulate rural service while not giving the larger companies who don't qualify for a small business bidding credit an unnecessary advantage.

289. The *Part 1 Report and Order* declines to adopt bidding preferences or credits based on criteria other than business size, except for the new rural service provider bidding credit. The repeal of the AMR rule, expanded eligibility for the DE program, and new rural service provider bidding credit are more than sufficient to address the challenges new entrants, minority- and women-owned companies, individuals who have overcome significant disadvantages, and service providers in areas that are unserved or underserved, areas of persistent poverty, and in tribal lands face today. The *Part 1 Report and Order* also declines proposals in the MMTC white paper, except for the proposal to repeal the AMR rule which was adopted. These additional proposed bidding credits or preferences, along with the other alternatives proposed to promote small business participation in the wireless sector, would add unnecessary complexity, which in turn could negatively affect the Commission's auction process.

290. The *Part 1 Report and Order's* modification of the Commission's DE reporting requirements reduces a significant regulatory burden placed on a DE by eliminating the requirement on DEs to provide information multiple times. Updating the deadline of the report reduces the administrative and related burdens on DEs. The DE reporting requirements provide a safeguard helping to prevent unjust enrichment. Additionally, the modifications adopted in the *Part 1 Report and Order* reduce administrative difficulties the Commission has in managing the information. The *Part 1 Report and Order* declines to eliminate the DE reporting rule altogether because other decisions, like the elimination of the AMR rule, have reduced the safeguards preventing unjust enrichment.

291. The *Part 1 Report and Order's* joint bidding rules are intended to preserve and promote robust competition in the mobile wireless marketplace and facilitate competition among bidders at auction, including small entities. These rules provide potential bidders with greater clarity regarding the types of joint bidding arrangements that would be permissible. In addition, the *Part 1 Report and Order's* rule to allow consortia and joint ventures among non-nationwide providers would maintain flexibility for small businesses to enter into such arrangements

292. Finally, the additional changes to the part 1 rules will apply to all entities in the same manner as the Commission will apply these changes uniformly to all entities that choose to participate in spectrum license auctions. The Commission believes that applying the same rules equally to all entities in these contexts promotes fairness. The Commission does not believe that the limited costs and/or administrative burdens associated with the rule revisions will unduly burden small entities. In fact, many of the proposed rule revisions clarify the Commission's competitive bidding rules, including short-form application requirements, as well as a reduction of reporting requirements.

G. Federal Rules That May Duplicate, Overlap, or Conflict With the Final Rules

293. None.

H. Report to Congress

294. The Commission will send a copy of the *Part 1 Report and Order,* including this FRFA, in a report to be

sent to Congress and the Government Accountability Office pursuant to the Congressional Review Act.

I. Report to Small Business Administration

295. The Commission's Consumer and Governmental Affairs Bureau, Reference Information Center, will send a copy of this *Part 1 Report and Order,* including this FRFA, to the Chief Counsel for Advocacy of the SBA.

VIII Ordering Clauses

296. *It is ordered* that, pursuant to sections 1, 4(i), 303(r), and 309(j) of the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), and 309(j), the *Part 1 Report and Order is adopted.*

297. *It is further ordered* that, pursuant to sections 1, 4(i), 303(r), and 309(j) of the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), and 309(j), the petitions for reconsideration of the *Order on Reconsideration of the First Report and Order* in WT Docket No. 05–211, filed by Blooston, Mordkofsky, Dickens, Duffy & Pendergast, LLP, and by the National Telecommunications Cooperative Association are *denied.*

298. *It is further ordered* that, pursuant to sections 1, 4(i), 303(r), and 309(j) of the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), and 309(j), the petition for partial reconsideration and/or clarification of the *Second Report and Order and Second Further Notice of Proposed Rule Making* in WT Docket No. 05–211 filed by Blooston, Mordkofsky, Dickens, Duffy & Pendergast, LLP, is, to the extent described herein, *denied* and otherwise is *dismissed as moot.*

299. *It is further ordered* that, pursuant to sections 1, 4(i), 303(r), and 309(j) of the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), and 309(j), the petition for reconsideration and clarification of the *Second Report and Order and Second Further Notice of Proposed Rule Making* in WT Docket No. 05–211 filed by Cook Inlet Region, Inc., is, to the extent described herein, *denied,* and otherwise is *dismissed as moot.*

300. *It is further ordered* that, pursuant to sections 1, 4(i), 303(r), and 309(j) of the Communications Act of 1934, as amended, 47 U.S.C. 151, 154(i), 303(r), and 309(j), consideration of the *Second Further Notice of Proposed Rule Making* in WT Docket No. 05–211 is *terminated.*

301. *It is further ordered* that the Commission's rules *are hereby amended* as set forth in Appendix A of the *Part 1 Report and Order.*

302. *It is further ordered* that the rules adopted herein *will become effective* November 17, 2015, except for §§ 1.2105(a)(2), 1.2105(a)(2)(iii) through (vi), (viii) through (x), and (xii), 1.2105(c)(3) through (4), 1.2110(j), 1.2110(n), 1.2112(b)(1)(iii) through (vi), 1.2112(b)(2)(iii), (v), and (vii) through (viii), 1.2114(a)(1), and 1.9020(e) which contain new or modified information collection requirements that require approval by the Office of Management and Budget (OMB). The Commission will publish a document in the **Federal Register** announcing the effective date of those sections.

303. *It is further ordered* that the Commission's Consumer and Governmental Affairs Bureau, Reference Information Center, *shall send* a copy of the *Part 1 Report and Order,* including the Final Regulatory Flexibility Analysis to the Chief Counsel for Advocacy of the Small Business Administration.

304. *It is further ordered* that the Commission *shall send* a copy of the *Part 1 Report and Order* in WT Docket Nos. 14–170 and 05–211, GN Docket No. 12–268, in a report to be sent to Congress and the Government Accountability Office pursuant to the Congressional Review Act, *see* 5 U.S.C. 801(a)(1)(A).

List of Subjects

47 CFR Part 1

Administrative practice and procedures.

47 CFR Part 27

Communications common carriers. Radio.

Federal Communications Commission.

Marlene H. Dortch,

Secretary.

Final Rules

For the reasons discussed in the preamble, the Federal Communications Commission amends 47 CFR parts 1 and 27 as follows:

PART 1—PRACTICE AND PROCEDURE

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

Authority: 15 U.S.C. 79 *et seq.;* 47 U.S.C. 151, 154(i), 154(j), 155, 157, 160, 201, 225, 227, 303, 309, 332, 1403, 1404, 1451, 1452, and 1455.

■ 1. Section 1.1910 is amended by revising paragraph (b)(3)(ii) to read as follows:

§ 1.1910 Effect of insufficient fee payments, delinquent debts, or debarment.

* * * * *

(b) * * *

(3) * * *

(ii) The provisions of paragraphs (b)(2) and (b)(3) of this section will not apply where more restrictive rules govern treatment of delinquent debtors, such as 47 CFR 1.2105(a)(2)(xi) and (xii).

* * * * *

■ 2. Section 1.2104 is amended by revising paragraph (j)(2) to read as follows:

§ 1.2104 Competitive bidding mechanisms

* * * * *

(j) * * *

(2) *Apportioned package bid.* The apportioned package bid on a license is an estimate of the price of an individual license included in a package of licenses in an auction with combinatorial (package) bidding. Apportioned package bids shall be determined by the Commission according to a methodology it establishes in advance of each auction with combinatorial bidding. The apportioned package bid on a license included in a package shall be used in place of the amount of an individual bid on that license when the bid amount is needed to determine the size of a designated entity bidding credit (see § 1.2110(f)(1), (f)(2), and (f)(4)), a new entrant bidding credit (see § 73.5007 of this chapter), a bid withdrawal or default payment obligation (see § 1.2104(g)), a tribal land bidding credit limit (see § 1.2110(f)(3)), or a size-based bidding credit unjust enrichment payment obligation (see § 1.2111(b), (c)(2) and (c)(3)), or for any other determination required by the Commission's rules or procedures.

■ 3. Section 1.2105 is revised to read as follows:

§ 1.2105 Bidding application and certification procedures; prohibition of certain communications.

(a) *Submission of Short-Form Application (FCC Form 175).* In order to be eligible to bid, an applicant must timely submit a short-form application (FCC Form 175), together with any appropriate upfront payment set forth by Public Notice. All short-form applications must be filed electronically.

(1) All short-form applications will be due:

(i) On the date(s) specified by public notice; or

(ii) In the case of application filing dates which occur automatically by operation of law, on a date specified by public notice after the Commission has reviewed the applications that have been filed on those dates and determined that mutual exclusivity exists.

(2) The short-form application must contain the following information, and all information, statements, certifications and declarations submitted in the application shall be made under penalty of perjury:

(i) Identification of each license, or category of licenses, on which the applicant wishes to bid.

(ii)(A) The applicant's name, if the applicant is an individual. If the applicant is a corporation, then the short-form application will require the name and address of the corporate office and the name and title of an officer or director. If the applicant is a partnership, then the application will require the name, citizenship and address of all general partners, and, if a partner is not a natural person, then the name and title of a responsible person should be included as well. If the applicant is a trust, then the name and address of the trustee will be required. If the applicant is none of the above, then it must identify and describe itself and its principals or other responsible persons; and

(B) Applicant ownership and other information, as set forth in § 1.2112.

(iii) The identity of the person(s) authorized to make or withdraw a bid. No person may serve as an authorized bidder for more than one auction applicant;

(iv) If the applicant applies as a designated entity, a certification that the applicant is qualified as a designated entity under § 1.2110.

(v) Certification that the applicant is legally, technically, financially and otherwise qualified pursuant to section 308(b) of the Communications Act of 1934, as amended;

(vi) Certification that the applicant is in compliance with the foreign ownership provisions of section 310 of the Communications Act of 1934, as amended. The Commission will accept applications certifying that a request for waiver or other relief from the requirements of section 310 is pending;

(vii) Certification that the applicant is and will, during the pendency of its application(s), remain in compliance with any service-specific qualifications applicable to the licenses on which the applicant intends to bid including, but not limited to, financial qualifications. The Commission may require certification in certain services that the applicant will, following grant of a license, come into compliance with certain service-specific rules, including, but not limited to, ownership eligibility limitations;

(viii) Certification that the applicant has provided in its application a brief description of, and identified each party to, any partnerships, joint ventures, consortia or other agreements, arrangements or understandings of any kind relating to the licenses being auctioned, including any agreements that address or communicate directly or indirectly bids (including specific prices), bidding strategies (including the specific licenses on which to bid or not to bid), or the post-auction market structure, to which the applicant, or any party that controls as defined in paragraph (a)(4) of this section or is controlled by the applicant, is a party.

(ix) Certification that the applicant (or any party that controls as defined in paragraph (a)(4) of this section or is controlled by the applicant) has not entered and will not enter into any partnerships, joint ventures, consortia or other agreements, arrangements, or understandings of any kind relating to the licenses being auctioned that address or communicate, directly or indirectly, bidding at auction (including specific prices to be bid) or bidding strategies (including the specific licenses on which to bid or not to bid), or post-auction market structure with: any other applicant (or any party that controls or is controlled by another applicant); with a nationwide provider that is not an applicant (or any party that controls or is controlled by such a nationwide provider); or, if the applicant is a nationwide provider, with any non-nationwide provider that is not an applicant (or with any party that controls or is controlled by such a non-nationwide provider), other than:

(A) Agreements, arrangements, or understandings of any kind that are solely operational as defined under paragraph (a)(4) of this section;

(B) Agreements, arrangements, or understandings of any kind to form consortia or joint ventures as defined under paragraph (a)(4) of this section;

(C) Agreements, arrangements or understandings of any kind with respect to the transfer or assignment of licenses, provided that such agreements, arrangements or understandings do not both relate to the licenses at auction and address or communicate, directly or indirectly, bidding at auction (including specific prices to be bid), or bidding strategies (including the specific licenses on which to bid or not to bid), or post-auction market structure.

(x) Certification that if applicant has an interest disclosed pursuant to § 1.2112(a)(1) through (6) with respect to more than one short-form application for an auction, it will implement internal controls that preclude any individual acting on behalf of the applicant as defined in paragraph (c)(5) of this section from possessing information about the bids or bidding strategies (including post-auction market structure), of more than one party submitting a short-form application or communicating such information with respect to a party submitting a short-form application to anyone possessing such information regarding another party submitting a short-form application.

(xi) Certification that the applicant is not in default on any Commission licenses and that it is not delinquent on any non-tax debt owed to any Federal agency.

(xii) A certification indicating whether the applicant has ever been in default on any Commission license or has ever been delinquent on any non-tax debt owed to any Federal agency. For purposes of this certification, an applicant may exclude from consideration as a former default any default on a Commission license or delinquency on a non-tax debt to any Federal agency that has been resolved and meets any of the following criteria:

(A) The notice of the final payment deadline or delinquency was received more than seven years before the short-form application deadline;

(B) The default or delinquency amounted to less than $100,000;

(C) The default or delinquency was paid within two quarters (*i.e.,* 6 months) after receiving the notice of the final payment deadline or delinquency; or

(D) The default or delinquency was the subject of a legal or arbitration proceeding that was cured upon resolution of the proceeding.

(xiii) For auctions required to be conducted under Title VI of the Middle Class Tax Relief and Job Creation Act of 2012 (Pub. L. 112–96) or in which any spectrum usage rights for which licenses are being assigned were made available under 47 U.S.C. 309(j)(8)(G)(i), certification under penalty of perjury that the applicant and all of the person(s) disclosed under paragraph (a)(2)(ii) of this section are not person(s) who have been, for reasons of national security, barred by any agency of the Federal Government from bidding on a contract, participating in an auction, or receiving a grant. For the purposes of this certification, the term ''person'' means an individual, partnership, association, joint-stock company, trust, or corporation, and the term ''reasons of national security'' means matters relating to the national defense and foreign relations of the United States.

(3) *Limit on filing applications.* In any auction, no individual or entity may file

more than one short-form application or have a controlling interest in more than one short-form application. In the case of a consortium, each member of the consortium shall be considered to have a controlling interest in the consortium. In the event that applications for an auction are filed by applicants with overlapping controlling interests, pursuant to paragraph (b)(1)(ii) of this section, both applications will be deemed incomplete and only one such applicant may be deemed qualified to bid. This limit shall not apply to any qualifying rural wireless partnership and individual members of such partnerships. A qualifying rural wireless partnership for purposes of this exception is one that was established as a result of the cellular B block settlement process established by the Commission in CC Docket No. 85–388 in which no nationwide provider is a managing partner or a managing member of the management committee, and partnership interests have not materially changed as of the effective date of the Report and Order in WT Docket No. 14–170, FCC 15–80. A partnership member for purposes of this exception is a partner or successor-in-interest to a partner in a qualifying partnership that does not have day-to-day management responsibilities in the partnership and holds 25% or less ownership interest, and provides a certification in its short-form application that it will implement internal controls to insulate itself from the bidding process of the cellular partnership and any other members of the partnership, except that it may, prior to the deadline for resubmission of short-form applications, express to the partnership the maximum it is willing to spend as a partner.

(4) *Definitions.* For purposes of the certifications required under paragraph (a)(2) of this section:

(i) The term *controlling interest* includes individuals or entities with positive or negative *de jure* or *de facto* control of the applicant. *De jure* control includes holding 50 percent or more of the voting stock of a corporation or holding a general partnership interest in a partnership. Ownership interests that are held indirectly by any party through one or more intervening corporations may be determined by successive multiplication of the ownership percentages for each link in the vertical ownership chain and application of the relevant attribution benchmark to the resulting product, except that if the ownership percentage for an interest in any link in the chain meets or exceeds 50 percent or represents actual control, it may be treated as if it were a 100 percent interest. *De facto* control is determined on a case-by-case basis. Examples of *de facto* control include constituting or appointing 50 percent or more of the board of directors or management committee; having authority to appoint, promote, demote, and fire senior executives that control the day-to-day activities of the licensee; or playing an integral role in management decisions. In the case of a consortium, each member of the consortium shall be considered to have a controlling interest in the consortium.

(ii) The term *consortium* means an entity formed to apply as a single applicant to bid at auction pursuant to an agreement by two or more separate and distinct legal entities that individually are eligible to claim the same designated entity benefits under § 1.2110, provided that no member of the consortium may be a nationwide provider;

(iii) The term *joint venture* means a legally cognizable entity formed to apply as a single applicant to bid at auction pursuant to an agreement by two or more separate and distinct legal entities, provided that no member of the joint venture may be a nationwide provider;

(iv) The term *solely operational agreement* means any agreement, arrangement, or understanding of any kind that addresses operational aspects of providing a mobile service, including but not limited to agreements for roaming, device acquisition, and spectrum leasing and other spectrum use arrangements, so long as the agreement does not both relate to the licenses at auction and address or communicate, directly or indirectly, bidding at auction (including specific prices to be bid) or bidding strategies (including the specific licenses on which to bid or not to bid), or post-auction market structure.

Note to paragraph (a): The Commission may also request applicants to submit additional information for informational purposes to aid in its preparation of required reports to Congress.

(b) *Modification and Dismissal of Short-Form Application (FCC Form 175).* (1) (i) Any short-form application (FCC Form 175) that does not contain all of the certifications required pursuant to this section is unacceptable for filing and cannot be corrected subsequent to the applicable filing deadline. The application will be deemed incomplete, the applicant will not be found qualified to bid, and the upfront payment, if paid, will be returned.

(ii) If:

(A) An individual or entity submits multiple applications in a single auction; or

(B) Entities commonly controlled by the same individual or same set of individuals submit applications for any set of licenses in the same or overlapping geographic areas in a single auction; then only one of such applications may be deemed complete, and the other such application(s) will be deemed incomplete, such applicants will not be found qualified to bid, and the associated upfront payment(s), if paid, will be returned.

(2) The Commission will provide bidders a limited opportunity to cure defects specified herein (except for failure to sign the application and to make certifications) and to resubmit a corrected application. During the resubmission period for curing defects, a short-form application may be amended or modified to cure defects identified by the Commission or to make minor amendments or modifications. After the resubmission period has ended, a short-form application may be amended or modified to make minor changes or correct minor errors in the application. Major amendments cannot be made to a short-form application after the initial filing deadline. Major amendments include changes in ownership of the applicant that would constitute an assignment or transfer of control, changes in an applicant's size which would affect eligibility for designated entity provisions, and changes in the license service areas identified on the short-form application on which the applicant intends to bid. Minor amendments include, but are not limited to, the correction of typographical errors and other minor defects not identified as major. An application will be considered to be newly filed if it is amended by a major amendment and may not be resubmitted after applicable filing deadlines.

(3) Applicants who fail to correct defects in their applications in a timely manner as specified by public notice will have their applications dismissed with no opportunity for resubmission.

(4) Applicants shall have a continuing obligation to make any amendments or modifications that are necessary to maintain the accuracy and completeness of information furnished in pending applications. Such amendments or modifications shall be made as promptly as possible, and in no case more than five business days after applicants become aware of the need to make any amendment or modification, or five business days after the reportable event occurs, whichever is later. An

applicant's obligation to make such amendments or modifications to a pending application continues until they are made.

(c) *Prohibition of certain communications.* (1) After the short-form application filing deadline, all applicants are prohibited from cooperating or collaborating with respect to, communicating with or disclosing, to each other or any nationwide provider that is not an applicant, or, if the applicant is a nationwide provider, any non-nationwide provider that is not an applicant, in any manner the substance of their own, or each other's, or any other applicants' bids or bidding strategies (including post-auction market structure), or discussing or negotiating settlement agreements, until after the down payment deadline, unless such communications are within the scope of an agreement described in paragraphs (a)(2)(ix)(A) through (C) of this section that is disclosed pursuant to paragraph (a)(2)(viii) of this section.

(2) Any party submitting a short-form application that has an interest disclosed pursuant to § 1.2112(a)(1) through (6) with respect to more than one short-form application for an auction must implement internal controls that preclude any individual acting on behalf of the applicant as defined for purposes of this paragraph from possessing information about the bids or bidding strategies of more than one party submitting a short-form or communicating such information with respect to a party submitting a short-form application to anyone possessing such information regarding another party submitting a short-form application. Implementation of such internal controls will not outweigh specific evidence that a prohibited communication has occurred, nor will it preclude the initiation of an investigation when warranted.

(3) An applicant must modify its short-form application to reflect any changes in ownership or in membership of a consortium or a joint venture or agreements or understandings related to the licenses being auctioned.

(4) A party that makes or receives a communication prohibited under paragraphs (c)(1) or (6) of this section shall report such communication in writing immediately, and in any case no later than five business days after the communication occurs. A party's obligation to make such a report continues until the report has been made. Such reports shall be filed as directed in public notices detailing procedures for the bidding that was the subject of the reported communication. If no public notice provides direction, the party making the report shall do so in writing to the Chief of the Auctions and Spectrum Access Division, Wireless Telecommunications Bureau, by the most expeditious means available, including electronic transmission such as email.

(5) For purposes of this paragraph:

(i) The term *applicant* shall include all controlling interests in the entity submitting a short-form application to participate in an auction (FCC Form 175), as well as all holders of partnership and other ownership interests and any stock interest amounting to 10 percent or more of the entity, or outstanding stock, or outstanding voting stock of the entity submitting a short-form application, and all officers and directors of that entity. In the case of a consortium, each member of the consortium shall be considered to have a controlling interest in the consortium; and

(ii) The term *bids* or *bidding strategies* shall include capital calls or requests for additional funds in support of bids or bidding strategies.

Example: Company A is an applicant in area 1. Company B and Company C each own 10 percent of Company A. Company D is an applicant in area 1, area 2, and area 3. Company C is an applicant in area 3. Without violating the Commission's Rules, Company B can enter into a consortium arrangement with Company D or acquire an ownership interest in Company D if Company B certifies either:

(*1*) That it has communicated with and will communicate neither with Company A or anyone else concerning Company A's bids or bidding strategy, nor with Company C or anyone else concerning Company C's bids or bidding strategy, or

(*2*) that it has not communicated with and will not communicate with Company D or anyone else concerning Company D's bids or bidding strategy.

(6) Prohibition of certain communications for the broadcast television spectrum incentive auction conducted under section 6403 of the Middle Class Tax Relief and Job Creation Act of 2012 (Pub. L. 112–96).

(i) For the purposes of the prohibition described in paragraphs (c)(6)(ii) and (iii) of this section, the term *forward auction applicant* is defined the same as the term *applicant* is defined in paragraph (c)(5) of this section, and the terms *full power broadcast television licensee* and *Class A broadcast television licensee* are defined the same as those terms are defined in § 1.2205(a)(1).

(ii) Except as provided in paragraph (c)(6)(iii) of this section, in the broadcast television spectrum incentive auction conducted under section 6403 of the Middle Class Tax Relief and Job Creation Act of 2012 (Pub. L. 112–96), beginning on the short-form application filing deadline for the forward auction and until the results of the incentive auction are announced by public notice, all forward auction applicants are prohibited from communicating directly or indirectly any incentive auction applicant's bids or bidding strategies to any full power or Class A broadcast television licensee.

(iii) The prohibition described in paragraph (c)(6)(ii) of this section does not apply to communications between a forward auction applicant and a full power or Class A broadcast television licensee if a controlling interest, director, officer, or holder of any 10 percent or greater ownership interest in the forward auction applicant, as of the deadline for submitting short-form applications to participate in the forward auction, is also a controlling interest, director, officer, or governing board member of the full power or Class A broadcast television licensee, as of the deadline for submitting applications to participate in the reverse auction.

Note 1 to Paragraph (c): For the purposes of paragraph (c), ''controlling interests'' include individuals or entities with positive or negative *de jure* or *de facto* control of the licensee. *De jure* control includes holding 50 percent or more of the voting stock of a corporation or holding a general partnership interest in a partnership. Ownership interests that are held indirectly by any party through one or more intervening corporations may be determined by successive multiplication of the ownership percentages for each link in the vertical ownership chain and application of the relevant attribution benchmark to the resulting product, except that if the ownership percentage for an interest in any link in the chain meets or exceeds 50 percent or represents actual control, it may be treated as if it were a 100 percent interest. *De facto* control is determined on a case-by-case basis. Examples of *de facto* control include constituting or appointing 50 percent or more of the board of directors or management committee; having authority to appoint, promote, demote, and fire senior executives that control the day-to-day activities of the licensee; or playing an integral role in management decisions.

Note 2 to Paragraph (c): The prohibition described in paragraph (c)(6)(ii) of this section applies to controlling interests, directors, officers, and holders of any 10 percent or greater ownership interest in the forward auction applicant as of the deadline for submitting short-form applications to participate in the forward auction, and any additional such parties at any subsequent point prior to the announcement by public notice of the results of the incentive auction. Thus, if, for example, a forward auction applicant appoints a new officer after the short-form application deadline, that new officer would be subject to the prohibition in paragraph (c)(6)(ii) of this section, but would not be included within the exception described in paragraph (c)(6)(iii) of this section.

■ 4. Section 1.2106 is amended by revising paragraph (a) to read as follows:

§ 1.2106 Submission of upfront payments.

(a) The Commission may require applicants for licenses subject to competitive bidding to submit an upfront payment. In that event, the amount of the upfront payment and the procedures for submitting it will be set forth in a Public Notice. Any auction applicant that, pursuant to § 1.2105(a)(2)(xii), certifies that it is a former defaulter must submit an upfront payment equal to 50 percent more than the amount that otherwise would be required. No interest will be paid on upfront payments.

* * * * *

■ 5. Section 1.2107 is amended by revising the first sentence in paragraph (g)(1)(i) to read as follows:

§ 1.2107 Submission of down payment and filing of long-form applications.

* * * * *

(g)(1)(i) A consortium participating in competitive bidding pursuant to § 1.2110(b)(4)(i) that is a winning bidder may not apply as a consortium for licenses covered by the winning bids. * * *

* * * * *

■ 6. Section 1.2110 is amended Amend § 1.2110 by:

■ A. Redesignating paragraphs (b)(3) as (b)(4);

■ B. Revising paragraphs (a), (b)(1)(i) and (ii), newly redesignated paragraph (b)(4)(i), and paragraphs (c)(6), (f)(2), (j) and (n);

■ C. Adding a new paragraph (b)(3), (c)(2)(ii)(J), and (f)(4); and

■ D. Removing newly redesignated paragraph (b)(4)(iv).

§ 1.2110 Designated entities.

(a) Designated entities are small businesses (including businesses owned by members of minority groups and/or women), rural telephone companies, and eligible rural service providers.

(b) * * *

(1) *Size attribution.* (i) The gross revenues of the applicant (or licensee), its affiliates, its controlling interests, and the affiliates of its controlling interests shall be attributed to the applicant (or licensee) and considered on a cumulative basis and aggregated for purposes of determining whether the applicant (or licensee) is eligible for status as a small business, very small business, or entrepreneur, as those terms are defined in the service-specific rules. An applicant seeking status as a small business, very small business, or entrepreneur, as those terms are defined in the service-specific rules, must disclose on its short- and long-form applications, separately and in the aggregate, the gross revenues for each of the previous three years of the applicant (or licensee), its affiliates, its controlling interests, and the affiliates of its controlling interests.

(ii) If applicable, pursuant to § 24.709 of this chapter, the total assets of the applicant (or licensee), its affiliates, its controlling interests, and the affiliates of its controlling interests shall be attributed to the applicant (or licensee) and considered on a cumulative basis and aggregated for purposes of determining whether the applicant (or licensee) is eligible for status as an entrepreneur. An applicant seeking status as an entrepreneur must disclose on its short- and long-form applications, separately and in the aggregate, the gross revenues for each of the previous two years of the applicant (or licensee), its affiliates, its controlling interests, and the affiliates of its controlling interests.

* * * * *

(3) *Standard for evaluating eligibility for small business benefits.* To be eligible for small business benefits:

(i) An applicant must meet the applicable small business size standard in paragraphs (b)(1) and (2) of this section, and

(ii) Must retain *de jure* and *de facto* control over the spectrum associated with the license(s) for which it seeks small business benefits. An applicant or licensee may lose eligibility for size-based benefits for one or more licenses without losing general eligibility for size-based benefits so long as it retains *de jure* and *de facto* control of its overall business.

(4) *Exceptions*—(i) *Consortium.* Where an applicant to participate in bidding for Commission licenses or permits is a consortium of entities eligible for size-based bidding credits and/or closed bidding based on gross revenues and/or total assets, the gross revenues and/or total assets of each consortium member shall not be aggregated. Where an applicant to participate in bidding for Commission licenses or permits is a consortium of entities eligible for rural service provider bidding credits pursuant to paragraph (f)(4) of this section, the subscribers of each consortium member shall not be aggregated. Each consortium member must constitute a separate and distinct legal entity to qualify for this exception. Consortia that are winning bidders using this exception must comply with the requirements of § 1.2107(g) of this chapter as a condition of license grant.

* * * * *

(c) * * *

(2) * * *

(ii) * * *

(J) In addition to the provisions of paragraphs (b)(1)(i) and (f)(4)(i)(C) of this section, for purposes of determining an applicant's or licensee's eligibility for bidding credits for designated entity benefits, the gross revenues (or, in the case of a rural service provider under paragraph (f)(4) of this section, the subscribers) of any disclosable interest holder of an applicant or licensee are also attributable to the applicant or licensee, on a license-by-license basis, if the disclosable interest holder uses, or has an agreement to use, more than 25 percent of the spectrum capacity of a license awarded with bidding credits. For purposes of this provision, a disclosable interest holder in a designated entity applicant or licensee is defined as any individual or entity holding a ten percent or greater interest of any kind in the designated entity, including but not limited to, a ten percent or greater interest in any class of stock, warrants, options or debt securities in the applicant or licensee. This rule, however, shall not cause a disclosable interest holder, which is not otherwise a controlling interest, affiliate, or an affiliate of a controlling interest of a rural service provider to have the disclosable interest holder's subscribers become attributable to the rural service provider applicant or licensee when the disclosable interest holder has a spectrum use agreement to use more than 25 percent of the spectrum capacity of a license awarded with a rural service provider bidding credit, so long as

(1) The disclosable interest holder is independently eligible for a rural service provider bidding credit, and;

(2) The disclosable interest holder's spectrum use and any spectrum use agreements are otherwise permissible under the Commission's rules.

* * * * *

(6) *Consortium.* A consortium of small businesses, very small businesses, entrepreneurs, or rural service providers is a conglomerate organization composed of two or more entities, each of which individually satisfies the definition of a small business, very

small business, entrepreneur, or rural service provider as those terms are defined in this section and in applicable service-specific rules. Each individual member must constitute a separate and distinct legal entity to qualify.

* * * * *

(f) * * *

(2) *Small business bidding credits.*

(i) *Size of bidding credits.* A winning bidder that qualifies as a small business, and has not claimed a rural service provider bidding credit pursuant to paragraph (f)(4) of this section, may use the following bidding credits corresponding to its respective average gross revenues for the preceding 3 years:

(A) Businesses with average gross revenues for the preceding 3 years not exceeding $4 million are eligible for bidding credits of 35 percent;

(B) Businesses with average gross revenues for the preceding 3 years not exceeding $20 million are eligible for bidding credits of 25 percent; and

(C) Businesses with average gross revenues for the preceding 3 years not exceeding $55 million are eligible for bidding credits of 15 percent.

(ii) *Cap on winning bid discount.* A maximum total discount that a winning bidder that is eligible for a small business bidding credit may receive will be established on an auction-by-auction basis. The limit on the discount that a winning bidder that is eligible for a small business bidding credit may receive in any particular auction will be no less than $25 million. The Commission may adopt a market-based cap on an auction-by-auction basis that would establish an overall limit on the discount that a small business may receive for certain license areas.

* * * * *

(4) *Rural service provider bidding credit*—(i) *Eligibility.* A winning bidder that qualifies as a rural service provider and has not claimed a small business bidding credit pursuant to paragraph (f)(2) of this section will be eligible to receive a 15 percent bidding credit. For the purposes of this paragraph, a rural service provider means a service provider that—

(A) Is in the business of providing commercial communications services and together with its controlling interests, affiliates, and the affiliates of its controlling interests as those terms are defined in paragraphs (c)(2) and (c)(5) of this section, has fewer than 250,000 combined wireless, wireline, broadband, and cable subscribers as of the date of the short-form filing deadline; and

(B) Serves predominantly rural areas, defined as counties with a population density of 100 or fewer persons per square mile.

(C) *Size attribution. (1)* The combined wireless, wireline, broadband, and cable subscribers of the applicant (or licensee), its affiliates, its controlling interests, and the affiliates of its controlling interests shall be attributed to the applicant (or licensee) and considered on a cumulative basis and aggregated for purposes of determining whether the applicant (or licensee) is eligible for the rural service provider bidding credit.

(2) Exception. For rural partnerships providing service as of July 16, 2015, the Commission will determine eligibility for the 15 percent rural service provider bidding credit by evaluating whether the individual members of the rural partnership individually have fewer than 250,000 combined wireless, wireline, broadband, and cable subscribers, and for those types of rural partnerships, the subscribers will not be aggregated.

(ii) *Cap on winning bid discount.* A maximum total discount that a winning bidder that is eligible for a rural service provider bidding credit may receive will be established on an auction-by-auction basis. The limit on the discount that a winning bidder that is eligible for a rural service provider bidding credit may receive in any particular auction will be no less than $10 million. The Commission may adopt a market-based cap on an auction-by-auction basis that would establish an overall limit on the discount that a rural service provider may receive for certain license areas.

* * * * *

(j) Designated entities must describe on their long-form applications how they satisfy the requirements for eligibility for designated entity status, and must list and summarize on their long-form applications all agreements that affect designated entity status such as partnership agreements, shareholder agreements, management agreements, spectrum leasing arrangements, spectrum resale (including wholesale) arrangements, spectrum use agreements, and all other agreements including oral agreements, establishing as applicable, *de facto* or *de jure* control of the entity. Designated entities also must provide the date(s) on which they entered into each of the agreements listed. In addition, designated entities must file with their long-form applications a copy of each such agreement. In order to enable the Commission to audit designated entity eligibility on an ongoing basis, designated entities that are awarded eligibility must, for the term of the license, maintain at their facilities or with their designated agents the lists, summaries, dates and copies of agreements required to be identified and provided to the Commission pursuant to this paragraph and to § 1.2114.

* * * * *

(n) *Annual reports.* (1) Each designated entity licensee must file with the Commission an annual report no later than September 30 of each year for each license it holds that was acquired using designated entity benefits and that, as of August 31 of the year in which the report is due (the ‘‘cut-off date’’), remains subject to designated entity unjust enrichment requirements (a ‘‘designated entity license’’). The annual report must provide the information described in paragraph (n)(2) of this section for the year ending on the cut-off date (the ‘‘reporting year’’). If, during the reporting year, a designated entity has assigned or transferred a designated entity license to another designated entity, the designated entity that holds the designated entity license on September 30 of the year in which the application for the transaction is filed is responsible for filing the annual report.

(2) The annual report shall include, at a minimum, a list and summaries of all agreements and arrangements (including proposed agreements and arrangements) that relate to eligibility for designated entity benefits. In addition to a summary of each agreement or arrangement, this list must include the parties (including affiliates, controlling interests, and affiliates of controlling interests) to each agreement or arrangement, as well as the dates on which the parties entered into each agreement or arrangement.

(3) A designated entity need not list and summarize on its annual report the agreements and arrangements otherwise required to be included under paragraphs (n)(1) and (n)(2) of this section if it has already filed that information with the Commission, and the information on file remains current. In such a situation, the designated entity must instead include in its annual report both the ULS file number of the report or application containing the current information and the date on which that information was filed.

* * * * *

■ 7. Section 1.2111 is amended by removing paragraphs (a) and (b); redesignating paragraphs (c), (d), and (e) as paragraphs (a), (b), and (c); and revising newly redesignated paragraphs (a)(2), (a)(3), and (b)(1) to read as follows:

§ 1.2111 Assignment or transfer of control: unjust enrichment.

(a) * * *

(2) If a licensee that utilizes installment financing under this section seeks to make any change in ownership structure that would result in the licensee losing eligibility for installment payments, the licensee shall first seek Commission approval and must make full payment of the remaining unpaid principal and any unpaid interest accrued through the date of such change as a condition of approval. A licensee's (or other attributable entity's) increased gross revenues or increased total assets due to nonattributable equity investments, debt financing, revenue from operations or other investments, business development or expanded service shall not be considered to result in the licensee losing eligibility for installment payments.

(3) If a licensee seeks to make any change in ownership that would result in the licensee qualifying for a less favorable installment plan under this section, the licensee shall seek Commission approval and must adjust its payment plan to reflect its new eligibility status. A licensee may not switch its payment plan to a more favorable plan.

* * * * *

(b) *Unjust enrichment payment: bidding credits.* (1) A licensee that utilizes a bidding credit, and that during the initial term seeks to assign or transfer control of a license to an entity that does not meet the eligibility criteria for a bidding credit, will be required to reimburse the U.S. Government for the amount of the bidding credit, plus interest based on the rate for ten year U.S. Treasury obligations applicable on the date the license was granted, as a condition of Commission approval of the assignment or transfer. If, within the initial term of the license, a licensee that utilizes a bidding credit seeks to assign or transfer control of a license to an entity that is eligible for a lower bidding credit, the difference between the bidding credit obtained by the assigning party and the bidding credit for which the acquiring party would qualify, plus interest based on the rate for ten year U.S. Treasury obligations applicable on the date the license is granted, must be paid to the U.S. Government as a condition of Commission approval of the assignment or transfer. If, within the initial term of the license, a licensee that utilizes a bidding credit seeks to make any ownership change that would result in the licensee losing eligibility for a bidding credit (or qualifying for a lower bidding credit), the amount of the bidding credit (or the difference between the bidding credit originally obtained and the bidding credit for which the licensee would qualify after restructuring), plus interest based on the rate for ten year U.S. Treasury obligations applicable on the date the license is granted, must be paid to the U.S. Government as a condition of Commission approval of the assignment or transfer or of a reportable eligibility event (*see* § 1.2114).

* * * * *

■ 8. Section 1.2112 is amended by revising paragraph (b) to read as follows:

§ 1.2112 Ownership disclosure requirements for applications.

* * * * *

(b) *Designated entity status.* In addition to the information required under paragraph (a) of this section, each applicant claiming eligibility for small business provisions or a rural service provider bidding credit shall disclose the following:

(1) On its application to participate in competitive bidding (*i.e.,* short-form application (*see* 47 CFR 1.2105)):

(i) List the names, addresses, and citizenship of all officers, directors, affiliates, and other controlling interests of the applicant, as described in § 1.2110, and, if a consortium of small businesses or consortium of very small businesses, the members of the conglomerate organization;

(ii) List any FCC-regulated entity or applicant for an FCC license, in which any controlling interest of the applicant owns a 10 percent or greater interest or a total of 10 percent or more of any class of stock, warrants, options or debt securities. This list must include a description of each such entity's principal business and a description of each such entity's relationship to the applicant;

(iii) List all parties with which the applicant has entered into agreements or arrangements for the use of any of the spectrum capacity of any of the applicant's spectrum;

(iv) List separately and in the aggregate the gross revenues, computed in accordance with § 1.2110, for each of the following: The applicant, its affiliates, its controlling interests, and the affiliates of its controlling interests; and if a consortium of small businesses, the members comprising the consortium;

(v) If claiming eligibility for a rural service provider bidding credit, provide all information to demonstrate that the applicant meets the criteria for such credit as set forth in § 1.2110(f)(4); and

(vi) If applying as a consortium of designated entities, provide the information in paragraphs (b)(1)(i) through (v) of this section separately for each member of the consortium.

(2) As an exhibit to its application for a license, authorization, assignment, or transfer of control:

(i) List the names, addresses, and citizenship of all officers, directors, and other controlling interests of the applicant, as described in § 1.2110;

(ii) List any FCC-regulated entity or applicant for an FCC license, in which any controlling interest of the applicant owns a 10 percent or greater interest or a total of 10 percent or more of any class of stock, warrants, options or debt securities. This list must include a description of each such entity's principal business and a description of each such entity's relationship to the applicant;

(iii) List and summarize all agreements or instruments (with appropriate references to specific provisions in the text of such agreements and instruments) that support the applicant's eligibility as a small business under the applicable designated entity provisions, including the establishment of *de facto* or *de jure* control. Such agreements and instruments include articles of incorporation and by-laws, partnership agreements, shareholder agreements, voting or other trust agreements, management agreements, franchise agreements, spectrum leasing arrangements, spectrum resale (including wholesale) arrangements, and any other relevant agreements (including letters of intent), oral or written;

(iv) List and summarize any investor protection agreements, including rights of first refusal, supermajority clauses, options, veto rights, and rights to hire and fire employees and to appoint members to boards of directors or management committees;

(v) List separately and in the aggregate the gross revenues, computed in accordance with § 1.2110, for each of the following: the applicant, its affiliates, its controlling interests, and affiliates of its controlling interests; and if a consortium of small businesses, the members comprising the consortium;

(vi) List and summarize, if seeking the exemption for rural telephone cooperatives pursuant to § 1.2110, all documentation to establish eligibility pursuant to the factors listed under § 1.2110(b)(4)(iii)(A).

(vii) List and summarize any agreements in which the applicant has entered into arrangements for the use of any of the spectrum capacity of the license that is the subject of the application; and

(viii) If claiming eligibility for a rural service provider bidding credit, provide all information to demonstrate that the applicant meets the criteria for such credit as set forth in § 1.2110(f)(4).

■ 9. Section 1.2114 is amended by revising paragraph (a)(1) to read as follows:

§ 1.2114 Reporting of eligibility event.

(a) * * *

(1) Any spectrum lease (as defined in § 1.9003) or any other type of spectrum use agreement with one entity or on a cumulative basis that might cause a licensee to lose eligibility for installment payments, a set-aside license, or a bidding credit (or for a particular level of bidding credit) under § 1.2110 and applicable service-specific rules.

* * * * *

■ 10. Section 1.2205 is amended by revising paragraph (a)(2) to read as follows:

§ 1.2205 Prohibition of certain communications.

(a) * * *

(2) For the purposes of this section, the term forward auction applicant is defined the same as the term applicant is defined in § 1.2105(c)(5).

* * * * *

■ 11. Section 1.9020 is amended by revising paragraphs (d)(4) and (e) to read as follows:

§ 1.9020 Spectrum manager leasing arrangements.

* * * * *

(d) * * *

(4) *Designated entity/entrepreneur rules.* A licensee that holds a license pursuant to small business, rural service provider, and/or entrepreneur provisions (*see* § 1.2110 and § 24.709 of this chapter) and continues to be subject to unjust enrichment requirements (*see* § 1.2111 and § 24.714 of this chapter) and/or transfer restrictions (*see* § 24.839 of this chapter) may enter into a spectrum manager leasing arrangement with a spectrum lessee, regardless of whether the spectrum lessee meets the Commission's designated entity eligibility requirements (*see* § 1.2110 of this chapter) or its entrepreneur eligibility requirements to hold certain C and F block licenses in the broadband personal communications services (*see* § 1.2110 and § 24.709 of this chapter), so long as the spectrum manager leasing arrangement does not result in the spectrum lessee's becoming a ''controlling interest'' or ''affiliate'' (*see* § 1.2110 of this chapter) of the licensee such that the licensee would lose its eligibility as a designated entity or entrepreneur.

* * * * *

(e) *Notifications regarding spectrum manager leasing arrangements.* A licensee that seeks to enter into a spectrum manager leasing arrangement must notify the Commission of the arrangement in advance of the spectrum lessee's commencement of operations under the lease. Unless the license covering the spectrum to be leased is held pursuant to the Commission's designated entity rules and continues to be subject to unjust enrichment requirements and/or transfer restrictions (*see* §§ 1.2110 and 1.2111, and §§ 24.709, 24.714, and 24.839 of this chapter), the spectrum manager lease notification will be processed pursuant to either the general notification procedures or the immediate processing procedures, as set forth herein. The licensee must submit the notification to the Commission by electronic filing using the Universal Licensing System (ULS) and FCC Form 608, except that a licensee falling within the provisions of § 1.913(d) of this chapter may file the notification either electronically or manually. If the license covering the spectrum to be leased is held pursuant to the Commission's designated entity rules, the spectrum manager lease will require Commission acceptance of the spectrum manager lease notification prior to the commencement of operations under the lease.

* * * * *

■ 12. Section 1.9030 is amended by revising the first two sentences in paragraphs (d)(4)(iii) and (iv) to read as follows:

§ 1.9030 Long-term de facto transfer leasing arrangements.

* * * * *

(d) * * *

(4) * * *

(iii) The amount of any unjust enrichment payment will be determined by the Commission as part of its review of the application under the same rules that apply in the context of a license assignment or transfer of control (*see* § 1.2111 and § 24.714 of this chapter). If the spectrum leasing arrangement involves only part of the license area and/or part of the bandwidth covered by the license, the unjust enrichment obligation will be apportioned as though the license were being partitioned and/or disaggregated (*see* § 1.2111(c) and § 24.714(c) of this chapter). * * *

(iv) A licensee that participates in the Commission's installment payment program (*see* § 1.2110(g)) may enter into a long-term de facto transfer leasing arrangement without triggering unjust enrichment obligations provided that the lessee would qualify for as favorable a category of installment payments. A licensee using installment payment financing that seeks to lease to an entity not meeting the eligibility standards for as favorable a category of installment payments must make full payment of the remaining unpaid principal and any unpaid interest accrued through the effective date of the spectrum leasing arrangement (*see* § 1.2111(a)). * * *

* * * * *

PART 27—MISCELLANEOUS WIRELESS COMMUNICATIONS SERVICES

■ 13. The authority citation for part 27 continues to read as follows:

Authority: 47 U.S.C. 154, 301, 302a, 303, 307, 309, 332, 336, 337, 1403, 1404, 1451, and 1452, unless otherwise noted.

■ 14. Section 27.1002 is amended by revising paragraph (a) to read as follows:

§ 27.1002 Designated entities in the 1915–1920 MHz and 1995–2000 MHz bands.

* * * * *

(a)(1) A small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $40 million for the preceding three years.

(2) A very small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $15 million for the preceding three years.

* * * * *

■ 15. Section 27.1104 is amended by revising paragraph (a) to read as follows:

§ 27.1104 Designated Entities in the 2000–2020 MHz and 2180–2200 MHz bands.

* * * * *

(a) *Small business.* (1) A small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $40 million for the preceding three years.

(2) A very small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $15 million for the preceding three years.

* * * * *

■ 16. Section 27.1106 is amended by revising paragraph (a) to read as follows:

§ 27.1106 Designated Entities in the 1695–1710 MHz, 1755–1780 MHz, and 2155–2180 MHz bands.

* * * * *

(a) *Small business.* (1) A small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $40 million for the preceding three (3) years.

(2) A very small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $15 million for the preceding three (3) years.

* * * * *

■ 17. Revise § 27.1301 to read as follows:

§ 27.1301 Designated entities in the 600 MHz band.

(a) *Small business.* (1) A small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $55 million for the preceding three (3) years.

(2) A very small business is an entity that, together with its affiliates, its controlling interests, and the affiliates of its controlling interests, has average gross revenues not exceeding $20 million for the preceding three (3) years.

(b) *Eligible rural service provider.* For purposes of this section, an eligible rural service provider is an entity that meets the criteria specified in § 1.2110(f)(4) of this chapter.

(c) *Bidding credits.* (1) A winning bidder that qualifies as a small business as defined in this section or a consortium of small businesses may use the bidding credit specified in § 1.2110(f)(2)(i)(C) of this chapter. A winning bidder that qualifies as a very small business as defined in this section or a consortium of very small businesses may use the bidding credit specified in § 1.2110(f)(2)(i)(B) of this chapter.

(2) An entity that qualifies as eligible rural service provider or a consortium of rural service providers may use the bidding credit specified in § 1.2110(f)(4) of this chapter.

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FEDERAL REGISTER

Part V

Nuclear Regulatory Commission

10 CFR Part 50

Incorporation by Reference of American Society of Mechanical Engineers Codes and Code Cases; Proposed Rule

NUCLEAR REGULATORY COMMISSION

10 CFR Part 50

[NRC–2011–0088]

RIN 3150–AI97

Incorporation by Reference of American Society of Mechanical Engineers Codes and Code Cases

AGENCY: Nuclear Regulatory Commission.

ACTION: Proposed rule.

SUMMARY: The U.S. Nuclear Regulatory Commission (NRC) is proposing to amend its regulations to incorporate by reference seven recent editions and addenda to the American Society of Mechanical Engineers (ASME) codes for nuclear power plants and a standard for quality assurance. The NRC is also proposing to incorporate by reference four ASME code cases. This action is in accordance with the NRC's policy to periodically update the regulations to incorporate by reference new editions and addenda of the ASME codes and is intended to maintain the safety of nuclear power plants and to make NRC activities more effective and efficient.

DATES: Submit comments by December 2, 2015. Comments received after this date will be considered if it is practical to do so, but the NRC is able to ensure consideration only for comments received on or before this date.

ADDRESSES: You may submit comments by any of the following methods (unless this document describes a different method for submitting comments on a specific subject):

• *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2011–0088. Address questions about NRC dockets to Carol Gallagher; telephone: 301–415–3463; email: *Carol.Gallagher@nrc.gov.* For technical questions contact the individuals listed in the **FOR FURTHER INFORMATION CONTACT** section of this document.

• *Email comments to: Rulemaking.Comments@nrc.gov.* If you do not receive an automatic email reply confirming receipt, then contact us at 301–415–1677.

• *Fax comments to:* Secretary, U.S. Nuclear Regulatory Commission at 301–415–1101.

• *Mail comments to:* Secretary, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001, ATTN: Rulemakings and Adjudications Staff.

• *Hand deliver comments to:* 11555 Rockville Pike, Rockville, Maryland 20852, between 7:30 a.m. and 4:15 p.m. (Eastern Time) Federal workdays; telephone: 301–415–1677.

For additional direction on obtaining information and submitting comments, see ''Obtaining Information and Submitting Comments'' in the **SUPPLEMENTARY INFORMATION** section of this document.

FOR FURTHER INFORMATION CONTACT: Daniel I. Doyle, Office of Nuclear Reactor Regulation, telephone: 301–415–3748, email: *Daniel.Doyle@nrc.gov;* or Keith Hoffman, Office of Nuclear Reactor Regulation, telephone: 301–415–1294, email: *Keith.Hoffman@nrc.gov.* Both are staff of the U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001.

SUPPLEMENTARY INFORMATION:

Executive Summary

A. Need for the Regulatory Action

The NRC is proposing to amend its regulations to incorporate by reference seven recent editions and addenda to the ASME codes for nuclear power plants and an ASME standard for quality assurance. The NRC is also proposing to incorporate by reference four ASME code cases.

This proposed rule is the latest in a series of rulemakings to amend the NRC's regulations to incorporate by reference revised and updated ASME codes for nuclear power plants. The ASME periodically revises and updates its codes for nuclear power plants by issuing new editions and addenda, and this rulemaking is in accordance with the NRC's policy to update the regulations to incorporate by reference those new editions and addenda. The incorporation by reference of the new editions and addenda will maintain the safety of nuclear power plants, make NRC activities more effective and efficient, and allow nuclear power plant licensees and applicants to take advantage of the latest ASME codes. The ASME is a voluntary consensus standards organization, and the ASME codes are voluntary consensus standards. The NRC's use of the ASME codes is consistent with applicable requirements of the National Technology Transfer and Advancement Act. Additional discussion of voluntary consensus standards and the NRC's compliance with the National Technology Transfer and Advancement Act (NTTAA) is set forth in Section VIII of this notice, ''Voluntary Consensus Standards.''

B. Major Provisions

Major provisions of the proposed rule include:

• Incorporation by reference of ASME codes into NRC regulations and delineation of NRC requirements for the use of these codes (including conditions).

• Incorporation by reference of various versions of quality assurance standard NQA–1 into NRC regulations and approval for their use.

• Incorporation by reference and approval of four ASME Code Cases.

C. Costs and Benefits

The NRC prepared a draft regulatory analysis to determine the expected costs and benefits of the proposed rule. The regulatory analysis identified costs and benefits in a quantitative fashion as well as in a qualitative fashion.

The analysis concluded that the proposed rule would result in net quantitative costs to the industry and the NRC. The proposed rule, relative to the regulatory baseline, would result in a net cost for industry of between $5.1 million based on a 7 percent net present value and $4.3 million based on a 3 percent net present value. The estimated incremental industry cost per reactor unit ranges from $49,000 based on a 7 percent net present value to $41,000 based on a 3 percent net present value. The NRC benefits from the proposed rulemaking alternative because of the averted cost of not reviewing and approving Code alternative requests on a plant-specific basis under § 50.55a(z) of title 10 of the *Code of Federal Regulations* (10 CFR). The NRC net benefit ranges from $1.4 million based on a 7 percent net present value to $1.9 million based on a 3 percent net present value.

Qualitative factors which were considered include regulatory stability and predictability, regulatory efficiency, and consistency with the NTTAA Act of 1995, as amended. Table 44 in the draft regulatory analysis includes a discussion of the costs and benefits that were considered qualitatively. If the results of the regulatory analysis were based solely on quantified costs and benefits, then the regulatory analysis would show that the rulemaking is not justified because the total quantified benefits of the proposed regulatory action do not equal or exceed the costs of the proposed action. However, if the qualitative benefits (including the safety benefit, cost savings, and other non-quantified benefits) are considered together with the quantified benefits, then the benefits outweigh the identified quantitative and qualitative impacts.

With respect to regulatory stability and predictability, the NRC has had a decades-long practice of approving and/

or mandating the use of certain parts of editions and addenda of these ASME Codes in 10 CFR 50.55a through the rulemaking process of ''incorporation by reference.'' Retaining the practice of approving and/or mandating the ASME Codes continues the regulatory stability and predictability provided by the current practice. Retaining the practice also assures consistency across the industry, and provides assurance to the industry and the public that the NRC will continue to support the use of the most updated and technically sound techniques developed by the ASME to provide adequate protection to the public. In this regard, these ASME Codes are voluntary consensus standards developed by participants with broad and varied interests and have already undergone extensive external review before being reviewed by the NRC. Finally, the NRC's use of the ASME Codes is consistent with the NTTAA, which directs Federal agencies to adopt voluntary consensus standards instead of developing ''government-unique'' (*i.e.,* Federal agency-developed) standards, unless inconsistent with applicable law or otherwise impractical.

For more information, please see the draft regulatory analysis (Accession No. ML14170B104 in the NRC's Agencywide Documents Access and Management System).

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I. Obtaining Information and Submitting Comments

A. Obtaining Information

Please refer to Docket ID NRC–2011–0088 when contacting the NRC about the availability of information for this proposed rule. You may obtain information related to this proposed rule by any of the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2011–0088.
- *NRC's Agencywide Documents Access and Management System (ADAMS):* You may obtain publicly-available documents online in the ADAMS Public Documents collection at *http://www.nrc.gov/reading-rm/adams.html.* To begin the search, select *''ADAMS Public Documents''* and then select *''Begin Web-based ADAMS Search.''* For problems with ADAMS, please contact the NRC's Public Document Room (PDR) reference staff at 1–800–397–4209, 301–415–4737, or by email to *pdr.resource@nrc.gov.* For the convenience of the reader, instructions about obtaining materials referenced in this document are provided in the ''Availability of Documents'' section.
- *NRC's PDR:* You may examine and purchase copies of public documents at the NRC's PDR, Room O1–F21, One White Flint North, 11555 Rockville Pike, Rockville, Maryland 20852.

B. Submitting Comments

Please include Docket ID NRC–2011–0088 in your comment submission.

The NRC cautions you not to include identifying or contact information that you do not want to be publicly disclosed in your comment submission. The NRC will post all comment submissions at *http://www.regulations.gov* as well as enter the comment submissions into ADAMS. The NRC does not routinely edit comment submissions to remove identifying or contact information.

If you are requesting or aggregating comments from other persons for submission to the NRC, then you should inform those persons not to include identifying or contact information that they do not want to be publicly disclosed in their comment submission. Your request should state that the NRC does not routinely edit comment submissions to remove such information before making the comment submissions available to the public or entering the comment into ADAMS.

II. Background

The ASME develops and publishes the ASME *Boiler and Pressure Vessel Code* (BPV Code), which contains requirements for the design, construction, and inservice inspection (ISI) of nuclear power plant components; and the ASME OM Code,[1] which contains requirements for inservice testing (IST) of nuclear power plant components. Until 2012, the ASME issued new editions of the ASME BPV Code every 3 years and addenda to the editions annually, except in years when a new edition was issued. Similarly, the ASME periodically published new editions and addenda of the ASME OM Code. Starting in 2012, the ASME decided to issue editions of its BPV and OM Codes (no addenda) every 2 years with the BPV Code to be issued on the odd years (*e.g.,* 2013, 2015, etc.) and the OM Code to be issued on the even years (*e.g.,* 2012, 2014, etc.). The new editions and addenda typically revise provisions of the Codes to broaden their applicability, add specific elements to current provisions, delete specific provisions, and/or clarify them to narrow the applicability of the provision. The revisions to the editions and addenda of the Codes do not significantly change Code philosophy or approach.

It has been the NRC's practice to establish requirements for the design, construction, operation, ISI (examination), and IST of nuclear power plants by approving the use of editions and addenda of the ASME BPV and OM Codes (ASME Codes) in § 50.55a. The NRC approves and/or mandates the use of certain parts of editions and addenda of these ASME Codes in § 50.55a through the rulemaking process of ''incorporation by reference.'' Upon incorporation by reference of the ASME Codes into § 50.55a, the provisions of the ASME Codes are legally-binding NRC requirements as delineated in § 50.55a, and subject to the conditions on certain specific ASME Codes' provisions that are set forth in § 50.55a. The editions and addenda of the ASME BPV and OM Codes were last incorporated by reference into the regulations in a final rule dated June 21, 2011 (76 FR 36232), subject to NRC conditions.

The ASME Codes are consensus standards developed by participants with broad and varied interests (including the NRC and licensees of nuclear power plants). The ASME's adoption of new editions of, and addenda to, the ASME Codes does not mean that there is unanimity on every provision in the ASME Codes. There may be disagreement among the technical experts, including NRC representatives on the ASME Code committees and subcommittees, regarding the acceptability or desirability of a particular Code

[1] The editions and addenda of the ASME *Code for Operation and Maintenance of Nuclear Power Plants* have had different titles from 2005 to 2012 and are referred to collectively in this rule as the ''OM Code.''

provision included in an ASME-approved code edition or addenda. If the NRC believes that there is a significant technical or regulatory concern with a provision in an ASME-approved Code edition or addenda being considered for incorporation by reference, then the NRC conditions the use of that provision when it incorporates by reference that ASME Code edition or addenda. In some cases, the condition increases the level of safety afforded by the ASME code provision, or addresses a regulatory issue not considered by the ASME. In other instances, where research data or experience has shown that certain Code provisions are unnecessarily conservative, the condition may provide that the Code provision need not be complied with in some or all respects. The NRC's conditions are included in § 50.55a, typically in paragraph (b) of that regulation. In a Staff Requirements Memorandum (SRM) dated September 10, 1999, the Commission indicated that NRC rulemakings adopting (incorporating by reference) a voluntary consensus standard must identify and justify each part of the standard that is not adopted. For this rulemaking, the provisions of the 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition of Section III, Division 1; and the 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition of Section XI, Division 1, of the ASME BPV Code; and the 2009 Edition, 2011 Addenda, and 2012 Edition of the ASME OM Code that the NRC is not adopting, or partially adopting, are identified in the Discussion, Regulatory Analysis, and Backfitting and Issue Finality sections of this notice. The provisions of those specific editions and addenda and Code Cases that are the subject of this rulemaking that the NRC finds to be conditionally acceptable, together with the applicable conditions, are also identified in the Discussion, Regulatory Analysis, and Backfitting and Issue Finality sections of this notice.

The ASME Codes are voluntary consensus standards, and the NRC's incorporation by reference of these Codes is consistent with applicable requirements of the NTTAA. Additional discussion on NRC's compliance with the NTTAA is set forth in Section VIII of this notice, ''Voluntary Consensus Standards.''

This proposed rule contains changes from a November 5, 2014, NRC final rule amending § 50.55a to, among other things, re-designate paragraphs within § 50.55a (79 FR 65776). The re-designation of paragraphs was needed to address the Office of the Federal Register's requirements in 10 CFR part 51 applicable to incorporation by reference. For additional information on the November 2014 final rule, please consult the statement of considerations (preamble) for that final rule.

III. Discussion

The NRC regulations incorporate by reference ASME codes for nuclear power plants. The ASME periodically revises and updates its codes for nuclear power plants. This proposed rule is the latest in a series of rulemakings to amend the NRC's regulations to incorporate by reference revised and updated ASME codes for nuclear power plants. This rulemaking is intended to maintain the safety of nuclear power plants and make NRC activities more effective and efficient.

The NRC follows a three-step process to determine acceptability of new provisions in new editions and addenda to the Codes and the need for conditions on the uses of these Codes. This process was employed in the review of the Codes that are the subjects of this rule. First, the NRC staff actively participates with other ASME committee members with full involvement in discussions and technical debates in the development of new and revised Codes. This includes a technical justification of each new or revised Code. Second, the NRC committee representatives discuss the Codes and technical justifications with other cognizant NRC staff to ensure an adequate technical review. Third, the NRC position on each Code is reviewed and approved by NRC management as part of the rule amending § 50.55a to incorporate by reference new editions and addenda of the ASME Codes and conditions on their use. This regulatory process, when considered together with the ASME's own process for developing and approving the ASME Codes, provides reasonable assurance that the NRC approves for use only those new and revised Code edition and addenda, with conditions as necessary, that provide reasonable assurance of adequate protection to public health and safety, and that do not have significant adverse impacts on the environment.

The NRC reviewed changes to the Codes in the editions and addenda of the Codes identified in this rulemaking. The NRC concluded, in accordance with the process for review of changes to the Codes, that each of the editions and addenda of the Codes, and the 2008 Edition and the 2009–1a Addenda of NQA–1, are technically adequate, consistent with current NRC regulations, and approved for use with the specified conditions.

The NRC proposes to amend its regulations to incorporate by reference:

- The 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition to the ASME BPV Code, Section III, Division 1 and Section XI, Division 1, with conditions on their use.
- The 2009 Edition, the 2011 Addenda, and the 2012 Edition to Division 1 of the ASME OM Code, with conditions on their use.
- ASME Standard NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications,'' including several editions and addenda to NQA–1 from previous years with slightly varying titles as identified in proposed rule language § 50.55a(a)(1)(v). More specifically, the NRC proposes to incorporate by reference the 1983 Edition through the 1994 Edition, the 2008 Edition, and the 2009–1a Addenda to the 2008 Edition of ASME NQA–1, with conditions on their use.
- ASME BPV Code Case N–729–4, ''Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds Section XI, Division 1,'' ASME approval date: June 22, 2012, with conditions on its use.
- ASME BPV Code Case N–770–2, ''Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities, Section XI, Division 1,'' ASME approval date: June 9, 2011, with conditions on its use.
- ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' ASME approval date: October 16, 2012.
- ASME OM Code Case OMN–20, ''Inservice Test Frequency.''

The current regulations in § 50.55a(a)(1)(ii) incorporate by reference ASME BPV Code, Section XI, 1970 Edition through the 1976 Winter Addenda; and the 1977 Edition (Division 1) through the 2008 Addenda (Division 1), subject to the conditions identified in current § 50.55a(b)(2)(i) through (b)(2)(xxix). The proposed amendment would revise § 50.55a(a)(1)(ii) to incorporate by reference the 2009 Addenda (Division 1) through the 2013 Edition (Division 1) of the ASME BPV Code, Section XI. It would also clarify the wording and add, remove, or revise some of the conditions as explained in this notice.

The NRC proposes to revise § 50.55a(a)(1)(iv) to incorporate by reference the 2009 Edition, 2011 Addenda, and 2012 Edition of Division 1 of the ASME OM Code. Based on this revision, the NRC regulations would incorporate by reference in § 50.55a the 1995 Edition through the 2012 Edition of the ASME OM Code.

Each of the proposed NRC conditions and the reasons for each proposed condition are discussed below. The discussions are organized under the applicable ASME Code and Section. Please note that there is not a separate heading for ASME quality assurance standard NQA–1 because there are three separate discussions of NQA–1—one under the heading for ASME BPV Code, Section III, one under the heading for ASME BPV Code, Section XI, and one under the heading for ASME OM Code—because there are three proposed conditions related to NQA–1, one in each of those areas (paragraph (b)(1)(iv) for Section III, paragraph (b)(2)(x) for Section XI, and paragraph (b)(3)(i) for the OM Code).

A. ASME BPV Code, Section III

10 CFR 50.55a(a)(1)(i) ASME Boiler and Pressure Vessel Code, Section III

The NRC proposes to clarify that Section III Nonmandatory Appendices are not incorporated by reference. This language was originally added in a final rule published on June 21, 2011 (76 FR 36232); however, it was omitted from the final rule published on November 5, 2014 (79 FR 65776). The NRC is correcting the omission by inserting ''(excluding Non-mandatory Appendices)'' in 10 CFR 50.55a(a)(1)(i).

10 CFR 50.55a(b)(1)(ii) Section III Condition: Weld Leg Dimensions

The NRC proposes to identify prohibited subparagraphs and footnotes for each BPV Code edition and addenda in tabular form as opposed to the textual listing of the current regulation. No substantive change to the requirements is intended by this revision. The NRC believes that presenting the information in tabular form will increase the clarity and understandability of the regulation.

Currently, § 50.55a(b)(1)(ii) includes a condition prohibiting the use of Footnote 11 from the 1989 Addenda through the 2003 Addenda or Footnote 13 from the 2004 Edition through the 2008 Addenda to Figures NC–3673.2(b)–1 and ND–3673.2(b)–1 for welds with leg sizes less than 1.09 t_n when using the ASME BPV Code, Section III, Division 1. These Code provisions provide stress indices for welded joints used in the design of Class 2 and Class 3 piping. The use of these indices is prohibited for welds with leg sizes less than 1.09 t_n, where t_n is the nominal pipe thickness. This is due to the fact that the current provisions would result in a weld that would be weaker than the pipe to which it is adjoined under these dimensions. The weld stress provisions in the version of the footnotes contained in the 1989 Addenda have been relocated to different subparagraphs in subsequent BPV Code editions and addenda. Therefore, the current Code's reference in Footnote 11 to Figures NC–3673.2(b)–1 and ND–3673.2(b)–1 is not correct for BPV Code editions and addenda after the 1989 Addenda, in applying the condition. The proposed rule would correct this issue by clearly identifying the prohibited code provisions in the editions and addenda in a tabular format.

As an editorial matter, this proposed rule identifies the prohibited BPV Code provisions as ''notes,'' which is the term used by the ASME, rather than ''footnotes.'' The NRC proposes to use the terminology used by the ASME for clarity.

10 CFR 50.55a(b)(1)(iv) Section III Condition: Quality Assurance

The NRC proposes to approve for use the version of NQA–1 referenced in the 2010 Edition, 2011 Addenda, and 2013 Edition of the ASME BPV Code, Section III, Subsection NCA, Article 7000, which this rule is also incorporating by reference. This will allow applicants and licensees to use the 2008 Edition and the 2009–1a Addenda of NQA–1 when using the 2010 and later editions and addenda of Section III.

In the 2010 Edition of ASME BPV Code, Section III, Subsection NCA, Article NCA–4000, ''Quality Assurance,'' was updated to require N-Type Certificate Holders to comply with the requirements of Part 1 of the 2008 Edition and the 2009–1a Addenda of ASME Standard NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications,'' as modified and supplemented in NCA–4120(b) and NCA–4134. In addition, NCA–4110(b) was revised to remove the reference to a specific edition and addenda of ASME NQA–1, and Table NCA–7100–2, ''Standards and Specifications Referenced in Division 1,'' was updated to require the 2008 Edition and 2009–1a Addenda of NQA–1 when using the 2010 Edition of Section III.

The NRC reviewed the 2008 Edition and the 2009–1a Addenda of NQA–1 and compared it to previously approved versions of NQA–1 and found that there were no significant differences. In addition, the NRC reviewed the changes to Subsection NCA that reference the 2008 Edition and 2009–1a Addenda of NQA–1, compared them to previously approved versions of Subsection NCA, and found that there were no significant differences. Therefore, the NRC has concluded that these Editions and Addenda of NQA–1 are acceptable for use.

The NRC proposes to revise § 50.55a(b)(1)(iv) to clarify that an applicant's or licensee's commitments, addressing those areas where NQA–1 either does not address a requirement in appendix B to 10 CFR part 50, ''Quality Assurance Criteria for Nuclear Power Plants and Fuel Reprocessing Plants,'' or is less stringent than the comparable appendix B requirement, governs the applicant's or licensee's Section III activities. The proposed clarification is consistent with § 50.55a(b)(2)(x) and § 50.55a(b)(3)(i). NQA–1 provides the ASME's method for establishing and implementing a quality assurance (QA) program for the design and construction of nuclear power plants and fuel reprocessing plants. However, NQA–1, as modified and supplemented in NCA–4120(b) and NCA–4134, does not address some of the requirements of appendix B to 10 CFR part 50. In some cases, the provisions of NQA–1 are less stringent than the comparable appendix B requirement. Thus, in order to meet the requirements of appendix B, an applicant's or licensee's QA program description must contain commitments addressing those provisions of appendix B which are not covered by NQA–1, as well as provisions that supplement or replace the NQA–1 provisions where the appendix B requirement is more stringent.

Finally, the NRC is considering removing the reference in § 50.55a(b)(1)(iv) to versions of NQA–1 older than the 1994 Edition. The NRC requests public comment on whether any applicant or licensee is committed to, and is using, a version of NQA–1 older than the 1994 Edition, and if so, what version the applicant or licensee is using.

10 CFR 50.55a(b)(1)(vii) Section III Condition: Capacity Certification and Demonstration of Function of Incompressible-Fluid Pressure-Relief Valves

The NRC proposes to revise § 50.55a(b)(1)(vii) so that the existing condition prohibiting the use of paragraph NB–7742(a)(2) of the 2006 Addenda through the 2007 Edition up to and including the 2008 Addenda is extended to include the editions and addenda up to the 2013 Edition which are the subject of this rulemaking.

10 CFR 50.55a(b)(1)(viii) Section III Condition: Use of ASME Certification Marks

The NRC is proposing to add new paragraph, § 50.55a(b)(1)(viii), to allow licensees to use either the ASME BPV Code Symbol Stamps of editions and addenda earlier than the 2011 Addenda to the 2010 Edition of the ASME BPV Code or the ASME Certification Marks with the appropriate certification designators and class designators as specified in the 2013 Edition through the latest edition and addenda incorporated by reference in 10 CFR 50.55a.

The ASME BPV Code requires, in certain instances, that components be stamped. The stamp signifies that the component has been designed, fabricated, examined and tested, as specified in the ASME BPV Code. The stamp also signifies that the required ASME BPV Code data report forms have been completed, and the authorized inspector has inspected the item and authorized the application of the ASME BPV Code Symbol Stamp.

The ASME has instituted changes in the BPV Code to consolidate the different ASME BPV Code Symbol Stamps into a common ASME Certification Mark. This action was implemented in the 2011 Addenda to the 2010 Edition of the ASME BPV Code. As of the end of 2012, ASME no longer utilizes the ASME BPV Code Symbol Stamp. Licensees, however, may not have updated to the Edition or Addenda that identifies the use of the ASME Certification Mark. Nevertheless, licensees are legally required to implement the ASME BPV Code Edition and Addenda identified as their current code of record. As ASME components are procured, these components may be received with the ASME Certification Mark, while the licensee's current code of record may require the component to have the ASME BPV Code Symbol Stamp. Installation of a component under such circumstances would not be in compliance with the regulations that the licensees are required to meet.

Both the ASME Certification Mark and the ASME BPV Code Symbol Stamp are official ASME methods of certifying compliance with the Code. Although these ASME Certification Marks differ slightly in appearance, they serve the same purpose of certifying code compliance by the ASME Certificate Holder and continue to provide for the same level of quality assurance for the application of the ASME Certification Mark as was required for the application of the ASME BPV Code Symbol Stamp. The new ASME Certification Mark represents a small, non-safety significant modification of ASME's trademark. As such, it does not change the technical requirements of the Code. ASME has confirmed that the Certification Mark with designator is equivalent to the corresponding BPV Code Symbol Stamp. Based on statements by ASME in a letter dated August 17, 2012, the NRC has concluded that the ASME BPV Code Symbol Stamps and ASME Certification Mark with code-specific designators are equivalent with respect to their certification of compliance with the BPV Code. The NRC discussed this issue in Regulatory Issue Summary 2013–07, ''NRC Staff Position on the Use of American Society of Mechanical Engineers Certification Mark,'' dated May 28, 2013.

B. ASME BPV Code, Section XI

10 CFR 50.55a(a)(1)(ii) ASME Boiler and Pressure Vessel Code, Section XI

The NRC proposes to revise § 50.55a(a)(1)(ii) to clarify that Section XI Non-mandatory Appendix U of the 2013 Edition of ASME BPV Code Section XI is not incorporated by reference and therefore not approved for use. The NRC is developing an integrated approach to the issue of operational leakage. The NRC has not completed its determination of how Appendix U fits into this integrated approach to address the operational leakage issue at nuclear power plants. The operational leakage issue has many factors that need to be considered such as acceptance criteria, corrective actions, application of repair/replacement requirements, component operability determination, concerns related to continued operation, maximum acceptable leakage rates, flaw growth rates, flaw measurement techniques, schedules for eliminating leakage, and when or if the leakage requires authorization by the NRC. The NRC plans to complete the development of the regulatory approach to operational leakage and issue it in a future rulemaking.

10 CFR 50.55a(b)(2)(vi) Section XI Condition: Effective Edition and Addenda of Subsection IWE and Subsection IWL

The NRC proposes to revise § 50.55a(b)(2)(vi) to explicitly state that the provision requiring the use of either the 1992 Edition with the 1992 Addenda or the 1995 Edition with the 1996 Addenda of Subsection IWE and Subsection IWL when implementing the initial 120-month containment inservice inspection program applies only to those licensees that were required by previous versions [2] of § 50.55a to develop and implement a containment inservice inspection program in accordance with Subsection IWE and Subsection IWL, and complete an expedited examination of containment during the 5-year period from September 9, 1996, to September 9, 2001.

The expedited examination involved the completion of the first set of examinations of the first or initial 120-month containment inspection interval. It is noted that all the operating reactors in the above stated class would have gone past their initial 120-month inspection interval by 2011. The proposed change removes the possibility of misinterpretation of the provision as requiring plants that do not fall in the above class, such as reactors licensed after September 9, 2001, to use the 1992 Edition with 1992 Addenda or the 1995 Edition with 1996 Addenda of Subsection IWE and Subsection IWL, Section XI for implementing the initial 120-month inspection interval of the containment inservice inspection program. Applicants and licensees that do not fall in the above class must use Code editions and addenda in accordance with § 50.55a(g)(4)(i) and (g)(4)(ii), respectively, for the initial and successive 120-month containment inservice inspection intervals.

10 CFR 50.55a(b)(2)(viii) Section XI Condition: Concrete Containment Examinations

The NRC proposes to revise § 50.55a(b)(2)(viii) by removing the condition for using the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL requiring compliance with § 50.55a(b)(2)(viii)(E) and adding a requirement to comply with § 50.55a(b)(2)(viii)(H) and (I).

Section 50.55a(b)(2)(viii)(E) is one of several conditions that apply to the inservice examination of concrete containments using Subsection IWL of various editions and addenda of the ASME BPV Code, Section XI, incorporated by reference in § 50.55a(a)(1)(ii). The NRC proposes to remove the condition in § 50.55a(b)(2)(viii)(E) when applying the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL because its intent has been incorporated into the Code in the new provision IWL–2512, ''Inaccessible Areas.'' The reasons for requiring compliance with § 50.55a(b)(2)(viii)(H) and (I) are set forth in the next two sections.

[2] See the supplementary information and rule language for § 50.55a(b)(2)(vi), § 50.55a(g)(4), and § 50.55a(g)(6)(ii)(B) in **Federal Register** notices published on August 8, 1996 (61 FR 41303), and September 22, 1999 (64 FR 51370).

10 CFR 50.55a(b)(2)(viii)(H) Concrete Containment Examinations: Eighth Provision

The NRC proposes to add a new paragraph, § 50.55a(b)(2)(viii)(H), to specify the information that must be provided in the ISI Summary Report required by IWA–6000, when inaccessible concrete surfaces are evaluated under the new code provision IWL–2512. This new condition would replace the existing condition in § 50.55a(b)(2)(viii)(E) when using the 2007 Edition with the 2009 Addenda through the 2013 Edition of Subsection IWL.

The existing condition in § 50.55a(b)(2)(viii)(E) of the current rule requires that, for Class CC applications, the licensee shall evaluate the acceptability of inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas, and provide the evaluation information required by §§ 50.55a(b)(2)(viii)(E)(*1*), (E)(*2*), and (E)(*3*) in the IWA–6000 ISI Summary Report.

In the 2009 Addenda Subsection IWL, the ASME revised existing provisions IWL–1220 and IWL–2510 and added new provision IWL–2512 intended to incorporate the condition in § 50.55a(b)(2)(viii)(E) into Subsection IWL. The IWL–2510, ''Surface Examination,'' was restructured into new paragraphs IWL–2511, ''Accessible Areas,'' with almost the same provisions as the previous IWL–2510 and IWL–2512, ''Inaccessible Areas,'' to be specific to examinations required for accessible areas, and differentiate between those and the new requirements for inaccessible areas. The inaccessible areas addressed by the new IWL–2512 are: (1) Concrete surfaces obstructed by adjacent structures, parts or appurtenances (*e.g.,* generally above-grade inaccessible areas) and (2) concrete surfaces made inaccessible by foundation material or backfill (*e.g.,* below-grade inaccessible areas).

The revised IWL–2511(a) has a new requirement that states that, ''If the Responsible Engineer determines that observed suspect conditions indicate the presence of, or could result in, degradation of inaccessible areas, the requirements of IWL–2512(a) shall be met.'' The new IWL–2512(a) requires the ''Responsible Engineer'' to evaluate suspect conditions and specify the type and extent of examinations, if any, required to be performed on inaccessible surface areas described in the previous paragraph. The acceptability of the evaluated inaccessible area would be determined either based on the evaluation or based on the additional examinations, if determined to be required. The new IWL–2512(b) further requires a periodic technical evaluation of below-grade inaccessible areas of concrete to be performed to determine and manage its susceptibility to degradation regardless of whether suspect conditions exist in accessible areas that would warrant an evaluation of inaccessible areas based on the condition in § 50.55a(b)(2)(viii)(E). Therefore, the revised IWL–2511(a) and new IWL–2512 code provisions address the evaluation and acceptability of inaccessible areas consistent with the existing condition in § 50.55a(b)(2)(viii)(E), with one exception. The exception is that the new IWL–2512 provision does not explicitly require the information specified in §§ 50.55a(b)(2)(viii)(E)(*1*), (E)(*2*), and (E)(*3*) of the existing condition to be provided in the IWA–6000 ISI Summary Report.

For these reasons, the NRC proposes to identify the information that must be provided in the ISI Summary Report required by IWA–6000 when inaccessible concrete surfaces are evaluated under the new code provision IWL–2512. This new condition would replace the existing condition in § 50.55a(b)(2)(viii)(E) when using the 2007 Edition with the 2009 Addenda through the 2013 Edition of Subsection IWL. The information requested by the new condition must be provided when inaccessible concrete areas are evaluated per IWL–2512(a) for degradation based on suspect conditions found in accessible areas, as well as when periodic technical evaluations of inaccessible below-grade concrete areas required by IWL–2512(b) are performed.

10 CFR 50.55a(b)(2)(viii)(I) Concrete Containment Examinations: Ninth Provision

The NRC proposes to add § 50.55a(b)(2)(viii)(I) to place a condition on the periodic technical evaluation requirements in the new IWL–2512(b), for consistency with NUREG–1801, Revision 2, ''Generic Aging Lessons Learned (GALL) Report,'' with regard to aging management of below-grade containment concrete surfaces. The new IWL–2512(b) provision is applicable to inaccessible below-grade concrete surfaces exposed to foundation soil, backfill, or groundwater. This condition would apply only during the period of extended operation of a renewed license under 10 CFR part 54, when using IWL–2512(b) of the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL.

In the 2009 Addenda of Subsection IWL, the ASME added new code provisions, IWL–2512(b) and (c) as well as a new line item L1.13 in Table IWL–2500–1, intended to specifically address aging management concerns with potentially unidentified degradation of inaccessible below-grade containment concrete areas and to be responsive to actions outlined in the GALL Report related to aging management of inaccessible below-grade concrete surfaces. It is noted that these new code provisions are an enhancement to the requirement of the existing condition in § 50.55a(b)(2)(viii)(E) to specifically address aging management of inaccessible below-grade containment concrete areas and is generally acceptable to the NRC.

The new IWL–2512(b) provides requirements for systematically performing a periodic technical evaluation of concrete surfaces exposed to foundation soil, backfill, or groundwater to determine susceptibility of the concrete to deterioration that could affect its ability to perform its intended design function under conditions anticipated through the service life of the structure. It requires the technical evaluation to be performed and documented at periodic intervals not to exceed 10 years regardless of whether conditions exist in accessible areas that would warrant an evaluation of inaccessible areas by the existing condition in § 50.55a(b)(2)(viii)(E), which the NRC finds reasonable for the initial 40-year operating license period. The new IWL–2512(b) further provides the specific elements, including aging mechanisms considered, that the technical evaluation should include, as well as the definition of an aggressive below-grade environment. The new IWL–2512(c) requires that the evaluation results of IWL–2512(b) be used to define and document the condition monitoring program, if determined to be required, including required examinations and frequencies, to be implemented for the management of degradation and aging effects of the below-grade concrete surface areas. If it is determined that additional examinations are required, these examinations of inaccessible below-grade areas will be implemented in accordance with new line item L1.13 in Table IWL–2500–1 under Examination Category L–A, Concrete, with acceptance criteria based on IWL–3210. It should be noted that a technical evaluation approach, such as in IWL–2512(b), could be used, and is generally used, to determine acceptability of a below-grade inaccessible area to satisfy the condition in § 50.55a(b)(2)(viii)(E).

The technical evaluation requirements in IWL–2512(b) help to determine the susceptibility to degradation and manage aging effects of inaccessible below-grade concrete surfaces, before the loss of intended function. The requirements are based on, and are generally consistent with, the guidance in the GALL Report,'' with the following two exceptions. The first exception is that IWL–2512(b) requires the technical evaluation to determine the susceptibility of the concrete to degradation and the ability to perform the intended design function through its service life at periodic intervals not to exceed 10 years. The aging management programs (AMPs) for safety-related structures (*e.g.,* Structures Monitoring) in the GALL Report require such evaluation to be performed at intervals not to exceed 5 years, which is also consistent with applicant commitments during review of license renewal applications. The second exception is that IWL–2512(b) requires that examination of representative samples of below-grade concrete be performed if excavated for any reason when an aggressive below-grade environment is present. However, the AMPs (X1.S6 Structures Monitoring and X1.S7 Water Control Structures) in the GALL Report require the same examination even for a non-aggressive below-grade environment.

Based on these reasons, the NRC proposes to add a new § 50.55a(b)(2)(viii)(I) to place a condition on the periodic technical evaluation requirements in IWL–2512(b) for consistency with the GALL Report, with regard to aging management of inaccessible below-grade concrete components of the containment. The new IWL–2512(b) is applicable to inaccessible below-grade concrete surfaces of the containment cylindrical wall and basemat foundations, which are exposed to foundation soil, backfill, or groundwater. The new condition requires that, during the period of extended operation of a renewed license, the technical evaluation under IWL–2512(b) of inaccessible below-grade concrete surfaces exposed to foundation soil, backfill, or groundwater be performed at periodic intervals not to exceed 5 years. Also, the condition requires the examination of representative samples of the exposed portions of the below-grade concrete be performed when excavated for any reason. Since the GALL Report is the technical basis document for license renewal, this new condition applies only during the period of extended operation of a renewed license under 10 CFR part 54, when using IWL–2512(b) of the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL, Section XI.

10 CFR 50.55a(b)(2)(ix) Section XI Condition: Metal Containment Examinations

The NRC proposes to continue to apply the existing conditions in §§ 50.55a(b)(2)(ix)(A)(*2*), (b)(2)(ix)(B), and (b)(2)(ix)(J) governing examinations of metal containments and the liners of concrete containments under Subsection IWE to the 2007 Edition with 2009 Addenda through the 2013 Edition (the code editions and addenda which are the subject of this rulemaking). The NRC reviewed the code changes in Subsection IWE of the 2009 Addenda through the 2013 Edition of ASME BPV Code, Section XI, and notes that all of the changes were editorial or administrative with the intent to improve the clarity of the existing requirements or correct errors by errata. There were no changes to Subsection IWE in the code editions and addenda that are the subject of this rulemaking that the NRC believes would require new regulatory conditions to ensure safety, nor do the changes to Subsection IWE address the NRC's reasons for adopting the conditions on the use of Subsection IWE. Although this continuation of the applicability of the three conditions does not require a rule change, the NRC is discussing this for the benefit of stakeholder understanding of the effect of the proposed rule.

10 CFR 50.55a(b)(2)(x) Section XI Condition: Quality Assurance

The NRC proposes to approve for use the version of NQA–1 referenced in the 2009 Addenda, 2010 Edition, 2011 Addenda, and the 2013 Edition of the ASME BPV Code, Section XI, Table IWA 1600–1, ''Referenced Standards and Specifications,'' which this rule is also incorporating by reference. This will allow licensees to use the 1994 or the 2008 Edition and the 2009–1a Addenda of NQA–1 when using the 2009 Addenda and later editions and addenda of Section XI.

In the 2013 Edition of ASME BPV Code, Section XI, Table IWA 1600–1 was updated to allow licensees to use the 1994 or the 2008 Edition with the 2009–1a Addenda of NQA–1 when using the 2013 Edition of Section XI. In the 2010 Edition of ASME BPV Code, Section XI, IWA–1400, ''Owner's Responsibilities,'' subparagraph (n)(2) was updated to reference the NQA–1 Part I, Basic Requirements and Supplementary Requirements for Nuclear Facilities. In the 2009 Addenda of the 2007 Edition of ASME BPV Code, Section XI, Table IWA–1600–1, ''Referenced Standards and Specifications,'' was updated to allow licensees to use the 1994 Edition of NQA–1. The NRC reviewed the 2008 Edition and the 2009–1a Addenda of NQA–1 and compared it to previously approved versions of NQA–1 and found that there were no significant differences. Therefore, the NRC has concluded that these Editions and Addenda of NQA–1 are acceptable for use.

The NRC proposes to amend § 50.55a(b)(2)(x) to clarify that a licensee's commitments addressing those areas where NQA–1 either does not address an appendix B requirement or is less stringent than the comparable appendix B requirement governs the licensee's Section XI activities. The proposed clarification is consistent with §§ 50.55a(b)(1)(iv) and (b)(3)(i). The ASME's method for establishing and implementing a QA program for the design and construction of nuclear power plants and fuel reprocessing plants is described in NQA–1. However, NQA–1 does not address some of the requirements of appendix B to 10 CFR part 50. In some cases, the provisions of NQA–1 are less stringent than the comparable appendix B requirement. Thus, in order to meet the requirements of appendix B, a licensee's QA program description must contain commitments addressing those provisions of appendix B which are not covered by NQA–1, as well as provisions that supplement or replace the NQA–1 provisions where the appendix B requirement is more stringent.

Finally, the NRC is considering removing the reference in § 50.55a(b)(2)(x) to versions of NQA–1 older than the 1994 Edition. The NRC requests public comment on whether any licensee is committed to, and is using, a version of NQA–1 older than the 1994 Edition, and if so, what version the applicant or licensee is using.

10 CFR 50.55a(b)(2)(xviii)(D) NDE Personnel Certification: Fourth Provision

The NRC proposes to add a new paragraph, § 50.55a(b)(2)(xviii)(D), to prohibit applicants and licensees from using the ultrasonic examination nondestructive examination (NDE) personnel certification requirements in Section XI, Appendix VII and subarticle VIII–2200 of the 2011 Addenda and 2013 Edition of the ASME BPV Code. Section 50.55a(b)(2)(xviii) currently includes conditions on the certification of NDE personnel. In addition, the new paragraph would require applicants and licensees to use the 2010 Edition, Table VII–4110–1 training hour requirements for Levels I, II, and III ultrasonic examination personnel, and the 2010 Edition, subarticle VIII–2200 of Appendix VIII prerequisites for personnel requirements. In the 2011 Addenda and 2013 Edition, the ASME BPV Code added an accelerated Appendix VII training process for certification of ultrasonic examination personnel based on training and prior experience, and separated the Appendix VII training requirements from the Appendix VIII qualification requirements. These new ASME BPV Code provisions would provide personnel in training with less experience and exposure to representative flaws in representative materials and configurations common to operating nuclear power plants, and they would permit personnel with prior non-nuclear ultrasonic examination experience to qualify for examinations in nuclear power plants without exposure to the variety of defects, examination conditions, components, and regulations common to operating nuclear power plants.

The impact of reduced training and nuclear power plant familiarization is unknown. The ASME BPV Code supplants training hours and field experience without a technical basis, minimum defined training criteria, process details, or standardization. For these reasons, the NRC is proposing to prohibit the use of Appendix VII and VIII–2200 in the 2011 Addenda and 2013 Edition, and instead require applicants and licensees using the 2011 Addenda and 2013 Edition to use Table VII–4110–1 in the 2010 Edition, and VIII–2200, Appendix VIII prerequisites for ultrasonic examination personnel requirements in the 2010 Edition.

10 CFR 50.55a(b)(2)(xxi)(A) Table IWB–2500–1 Examination Requirements: First Provision

The NRC proposes to revise § 50.55a(b)(2)(xxi)(A) to modify the standard for visual magnification resolution sensitivity and contrast for visual examinations performed on Examination Category B–D components instead of ultrasonic examinations, making the rule conform with ASME BPV Code, Section XI requirements for VT–1 examinations. The character recognition rules are used in ASME BPV Code, Section XI, Table IWA–2211–1 for VT–1 tests, and are the standard tests used for resolution and contrast checks of VT–1 equipment. This revision essentially removes a requirement that was in addition to ASME BPV Code that required 1-mil wires to be used in licensees' Sensitivity, Resolution and Contrast Standard targets. In 2004, the NRC published NUREG/CR–6860, ''An Assessment of Visual Testing,'' showing that a linear target, such as a wire, is not an effective method for testing the resolution of a video camera system. In addition, BWRVIP–03 was changed to eliminate a ½ mil wire from the Sensitivity Resolution and Contrast Standards due to similar concerns.

Simple line detection can be a poor performance standard, allowing detection of a highly blurred image. This does not emulate sharpness quality recognition for evaluation of weld discontinuities. The 750 μm (30 mil) and the even smaller 25 μm (1 mil) widths should not be used as performance standards because they do not determine image sharpness. This technique only measures the ''visible minimum'' for long linear indications, and does not measure a system's resolution or recognition limits. If the wire, or printed line, has a strong enough contrast against the background, then a linear feature well below the resolution of a system can be detected.

10 CFR 50.55a(b)(2)(xxx) Section XI Condition: Steam Generator Preservice Examinations

The NRC proposes to add § 50.55a(b)(2)(xxx) to require a full length examination of 100 percent of the tubing in each newly installed steam generator prior to plant startup. This requirement would be instead of the unapproved provisions in IWB–2200(c) pertaining to steam generator tube preservice inspections (PSI).

Steam generator tubes, a significant portion of the reactor coolant pressure boundary, are important to the safe operation of a pressurized water reactor. As such, the NRC has established requirements pertaining to the design, fabrication, erection, testing, and inspection of the steam generator tubes. With respect to the performance of the PSI of steam generator tubes, the NRC has indicated in NRC Regulatory Guide (RG) 1.83, Revision 1, ''Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes,'' (withdrawn in 2009) that all tubes in the steam generator should be inspected by eddy current or alternative technique prior to service to establish a baseline condition of the tubing. A similar position is articulated in NUREG–0800, Standard Review Plan (SRP) Section 5.4.2.2, ''Steam Generator Tube Inservice Inspection,'' Revision 1 and subsequent revisions. A PSI is important since it ensures that the steam generator tubes are acceptable for initial operation. In addition, the PSI provides the baseline condition of the tubes. This data is essential in assessing the nature of indications found in the tubes during subsequent inservice inspections.

Preservice requirements for ASME Class 1 components are provided in IWB–2200, and IWB–2200(c) currently states, ''Steam generator tube examination shall be governed by the plant Technical Specifications (TS).'' However, there are no preservice examination requirements for steam generators defined in plant TS. Preservice examination requirements for steam generators are not within any of the categories described in 50.36 for the content of TS. Because IWB–2200(c) requires the steam generator tube examinations be performed in accordance with plant TS, and TS contain no rules for PSI of steam generator tubing, the NRC is clarifying the preservice inspection requirements for steam generator tubes.

The proposed clarification is consistent with industry guidelines and the NRC staff position outlined in SRP Section 5.4.2.2, ''Steam Generator Program.'' The proposed requirement supersedes the requirements of IWB–2200(c). These inspections must be performed with the objective of finding and characterizing the types of preservice flaws that may be present in the tubes and flaws that may occur during operation.

10 CFR 50.55a(b)(2)(xxxi) Section XI Condition: Mechanical Clamping Devices

The NRC proposes to add § 50.55a(b)(2)(xxxi) to prohibit the use of mechanical clamping devices on Class 1 piping and portions of piping systems that form the containment boundary. In the 2010 Edition of the ASME BPV Code, a change was made to include mechanical clamping devices under the small items exclusion rules of IWA–4131. Currently in the 2007 Edition/2008 Addenda of Section XI under IWA–4133, ''Mechanical Clamping Devices Used as Piping Pressure Boundary,'' mechanical clamping devices may be used only if they meet the requirements of Mandatory Appendix IX of Section XI of the ASME BPV Code. Article IX–1000 (c) of Appendix IX prohibits the use of mechanical clamping devices on (1) Class 1 piping and (2) portions of a piping system that form the containment boundary.

In the 2010 Edition, IWA–4133 was modified to allow use of IWA–4131.1(c) for the installation of mechanical clamping devices. This change allowed the use of small items exemption rules in the installation of mechanical clamps. Subparagraph IWA–4131.1(c) was added such that mechanical clamping devices installed on items classified as ''small items'' under IWA–4131, including Class 1 piping and portions of a piping system that form the containment boundary, would be allowed without a repair/replacement plan, pressure testing, services of an Authorized Inspection Agency, and completion of NIS–2 form.

The NRC, in accordance with the previously approved IWA–4133 of the 2007 Edition/2008 Addenda of the ASME BPV Code, does not believe that the ASME has provided a sufficient technical basis to support the use of mechanical clamps on Class 1 piping or portions of a piping system that form the containment boundary as a permanent repair. Furthermore, the NRC does not believe that the ASME has provided any basis for the small item exemption allowing the installation of mechanical clamps on these components. In the 2011 Addenda of the ASME BPV Code, IWA–4131.1(c) was relocated to IWA–4131.1(d).

10 CFR 50.55a(b)(2)(xxxii) Section XI Condition: Summary Report Submittal

The NRC proposes to add § 50.55a(b)(2)(xxxii) to require licensees using the 2010 Edition and later editions and addenda of Section XI to continue to submit Summary Reports as required in IWA–6240 of the 2009 Addenda.

Prior to the 2010 Edition, Section XI required the preservice summary report to be submitted prior to the date of placement of the unit into commercial service, and the inservice summary report to be submitted within 90 calendar days of the completion of each refueling outage. In the 2010 Edition, IWA–6240 was revised to state, ''Summary Reports shall be submitted to the enforcement and regulatory authorities having jurisdiction at the plant site, if required by these authorities.'' This change in the 2010 Edition could lead to confusion as to whether or not the summary reports need to be submitted to the NRC, as well as the time for submitting the reports if they were required. The NRC believes that summary reports must continue to be submitted to the NRC in a timely manner because they provide valuable information regarding examinations performed, conditions noted, corrective actions taken, and the implementation status of PSI and ISI programs. Therefore, the NRC proposes adding § 50.55a(b)(2)(xxxii) to ensure that preservice and inservice summary reports will continue to be submitted within the timeframes currently established in Section XI editions and addenda prior to the 2010 Edition.

10 CFR 50.55a(b)(2)(xxxiii) Section XI Condition: Risk-Informed Allowable Pressure

The NRC proposes to add § 50.55a(b)(2)(xxxiii) to prohibit the use of Appendix G Paragraph G–2216 in the 2011 Addenda and later editions and addenda of the ASME BPV Code, Section XI. The 2011 Addenda of the ASME BPV Code included, for the first time, a risk-informed methodology to compute allowable pressure as a function of inlet temperature for reactor heat-up and cool-down at rates not to exceed 100 degrees F/hr (56 degrees C/hr). This methodology was developed based upon probabilistic fracture mechanics (PFM) evaluations that investigated the likelihood of reactor pressure vessel (RPV) failure based on specific heat-up and cool-down scenarios.

During the ASME's consideration of this change, the NRC staff noted that additional requirements would need to be placed on the use of this alternative. For example, the NRC staff indicated that it would be important for a licensee who wishes to utilize such a risk-informed methodology for determining plant-specific pressure-temperature limits to ensure that the material condition of its facility is consistent with assumptions made in the PFM evaluations that supported the development of the methodology. One aspect of this would be evaluating plant-specific inservice inspection data to determine whether the facility's RPV flaw distribution was consistent with the flaw distribution assumed in the supporting PFM evaluations. This consideration is consistent with a similar requirement established by the NRC in § 50.61a, ''Alternative Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events.'' The PFM methodology that supports § 50.61a is very similar that which was used to support ASME BPV Code, Section XI, Appendix G, Paragraph G–2216. These concerns with the Paragraph G–2216 methodology for computing allowable pressure as a function of inlet temperature for reactor heat-up and cooldown were not addressed by the ASME. Accordingly, the NRC is proposing to prohibit the use of Paragraph G–2216 in Appendix G of the 2010 Edition. The continued use of the deterministic methodology of Section XI, Appendix G to generate P–T limits remains acceptable.

10 CFR 50.55a(b)(2)(xxxiv) Section XI Condition: Disposition of Flaws in Class 3 Components

The NRC proposes to add § 50.55a(b)(2)(xxxiv) to require that when using the 2013 Edition of the ASME BPV Code, Section XI, the licensee shall use the acceptance standards of IWD–3510 for the disposition of flaws in Category D–A components (*i.e.,* welded attachments for vessels, piping, pumps, and valves).

The 2013 Edition of the ASME BPV Code, Section XI, IWD–3510, ''Standards for Examination Category D–A, Welded Attachments for Vessels, Piping, Pumps, and Valves,'' states that the acceptance standards are: ''In the course of preparation, the requirements of IWC–3500 may be used.'' The ASME BPV Code, Section XI, IWD–3410, ''Acceptance Standards,'' states that the acceptance standards referenced in Table IWD–3410–1 shall be applied to determine acceptability for service. Table IWD–3410–1 states that the acceptance standard for Examination Category D–A is IWB–3510.

A discrepancy exists between the provisions in IWD–3410, which references Table IWD–3410–1, and the provisions in IWD–3510. The provisions in IWD–3510 require the use of the acceptance standards of IWC–3500 whereas Table IWD–3410–1 requires the use of the acceptance standards of IWB–3510 to disposition flaws detected in the Examination Category D–A components. Both IWD–3410 and IWD–3510 should reference the same subarticle and acceptance standards. The NRC believes that this discrepancy is due to an error in the publishing of the 2013 Edition because the code committee action which proposed the revised Class 3 acceptance criteria and added Table IWD–3410–1 showed the appropriate Acceptance Standard to be IWD–3510. The intent of the condition is to provide clarification and consistency in requirements between IWD–3410 and IWD–3510.

10 CFR 50.55a(b)(2)(xxxv) Section XI Condition: Use of RT_{T0} in the K_{Ia} and K_{Ic} Equations

The NRC proposes to add § 50.55a(b)(2)(xxxv) to specify that when licensees use the 2013 Edition of the ASME BPV Code, Section XI, Appendix A, paragraph A–4200, if T_0 is available, then RT_{T0} may be used in place of RT_{NDT} for applications using the K_{Ic} equation and the associated K_{Ic} curve, but not for applications using the K_{Ia} equation and the associated K_{Ia} curve.

Non-mandatory Appendix A provides a procedure based on linear elastic fracture mechanics (LEFM) for determining the acceptability of flaws that have been detected during inservice inspections that exceed the allowable flaw indication standards of IWB–3500. Sub-article A–4200 provides a procedure for determining fracture toughness of the material used in the LEFM analysis. The NRC staff's concern is related to the proposed insertion regarding an alternative based on Master Curve methodology to determine the nil-ductility transition reference temperature RT_{NDT}, which is an important parameter in determining the fracture toughness of the material. Specifically, the insertion proposed to use Master Curve reference temperature RT_{T0}, which is defined as $RT_{T0} = T_0 + 35$ °F, where T_0 is a material-specific temperature value determined in accordance with ASTM E1921, ''Standard Test Method for Determination of Reference Temperature, T_0, for Ferritic Steels in the Transition Range,'' to index (shift) the fracture toughness K_{Ic} curve, based on the lower bound of static initiation critical stress intensity factor, as well as the K_{Ia} curve, based on the lower bound of crack arrest critical stress intensity factor.

While use of RT_{T0} to index the K_{Ic} curve is acceptable, using RT_{T0} to index the K_{Ia} curve is questionable. This NRC staff concern is based on the data analysis in ''A Physics-Based Model for the Crack Arrest Toughness of Ferritic Steels,'' written by NRC staff member Mark Kirk, and published in ''Fatigue and Fracture Mechanics, 33rd Volume, ASTM STP 1417,'' which indicated that the crack arrest data does not support using RT_{T0} as RT_{NDT} to index the K_{Ia} curve. This is also confirmed by industry data disclosed in a presentation, ''Final Results from the CARINA Project on Crack Initiation and Arrest of Irradiated German RPV Steels for Neutron Fluences in the Upper Bound,'' by AREVA at the 26th Symposium on Effects of Radiation on Nuclear Materials (June 12–13, 2013, Indianapolis, IN, USA). The NRC staff recognized that the proposed insertion is consistent with Code Case N–629, ''Use of Fracture Toughness Test Data to Establish Reference Temperature for Pressure Retaining Materials,'' which was accepted by the NRC without conditions. In addition to the current NRC effort, the appropriate ASME Code committee is in the process of correcting this issue in a future revision of Appendix A of Section XI.

With this condition, users of Appendix A can avoid using an erroneous fracture toughness K_{Ia} value in their LEFM analysis for determining the acceptability of a detected flaw in applicable components. Therefore, the NRC is proposing to add a condition which permits the use of RT_{T0} in place of RT_{NDT} in applications using the K_{Ic} equation and the associated K_{Ic} curve, but does not permit the use of RT_{T0} in place of RT_{NDT} in applications using the K_{Ia} equation and the associated K_{Ia} curve.

10 CFR 50.55a(b)(2)(xxxvi) Section XI Condition: Fracture Toughness of Irradiated Materials

The NRC proposes to add § 50.55a(b)(2)(xxxvi) to require licensees using ASME BPV Code, Section XI, 2013 Edition, Appendix A, paragraph A–4400, to obtain NRC approval before using irradiated T_0 and the associated RT_{T0} in establishing fracture toughness of irradiated materials.

Sub-article A–4400 provides guidance for considering irradiation effects on materials. The NRC staff's concern is related to use of RT_{T0} based on measured T_0 of the irradiated materials. Specifically, the NRC staff has concerns over this sentence in the proposed insertion: ''Measurement of RT_{T0} of unirradiated or irradiated materials as defined in A–4200(b) is permitted, including use of the procedures given in ASTM E1921 to obtain direct measurement of irradiated T_0.''

Permission of measurement of RT_{T0} of irradiated materials, without providing guidelines regarding how to use the measured parameter in determining the fracture toughness of the irradiated materials, may mislead the users of Appendix A into adopting methodology not accepted by the NRC. With this condition, users of Appendix A can avoid using a fracture toughness K_{Ic} value based on the irradiated T_0 and the associated RT_{T0} in their LEFM analysis for determining the acceptability of a detected flaw in applicable components.

10 CFR 50.55a(g) Inservice and Preservice Inspection Requirements

The NRC proposes to add new paragraphs (g)(2)(i), (g)(2)(ii), and (g)(2)(iii) and to revise paragraphs (g), (g)(2), (g)(3), (g)(3)(i), (g)(3)(ii), and (g)(3)(v) to distinguish the requirements for accessibility and preservice examination from those for inservice inspection in § 50.55a(g). No substantive change to the requirements is intended by these revisions.

C. ASME OM Code

10 CFR 50.55a(b)(3) Conditions on ASME OM Code

The NRC proposes to revise § 50.55a(b)(3) to clarify that Subsections ISTA, ISTB, ISTC, ISTD, ISTE, and ISTF; Mandatory Appendices I, II, III, and V; and Non-mandatory Appendices A through H and J through M of the ASME OM Code would be incorporated by reference in § 50.55a. The NRC is clarifying that the ASME OM Code non-mandatory appendices, which are incorporated by reference into § 50.55a are approved for use, but are not mandated. The non-mandatory appendices may be used by applicants and licensees of nuclear power plants, subject to the conditions in § 50.55a(b)(3).

10 CFR 50.55a(b)(3)(i) OM Condition: Quality Assurance

The NRC proposes to revise § 50.55a(b)(3)(i) to allow use of the 1983 Edition through the 1994 Edition, 2008 Edition, and the 2009–1a Addenda of NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications.'' The NRC reviewed these Editions and Addenda after the 1983 Edition and compared them to the previously approved versions of NQA–1 and found that there were no significant differences.

The NRC is considering removing the reference in § 50.55a(b)(3)(i) to versions of NQA–1 older than the 1994 Edition. The NRC requests public comment on whether any licensee is committed to, and is using, a version of NQA–1 older than the 1994 Edition and, if so, what version the applicant or licensee is using.

10 CFR 50.55a(b)(3)(ii) OM Condition: Motor-Operated Valve (MOV) Testing

The NRC proposes to revise § 50.55a(b)(3)(ii) to reflect the new Appendix III, ''Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants,'' of the ASME OM Code, 2009 Edition, 2011 Addenda, and 2012 Edition. Appendix III of the ASME OM Code establishes provisions for periodic verification of the design-basis capability of MOVs within the scope of the IST program. Appendix III of the ASME OM Code reflects the incorporation of ASME OM Code Cases OMN–1, ''Alternative Rules for Preservice and Inservice Testing of Active Electric Motor-Operated Valve Assemblies in Light-Water Reactor Power Plants,'' and OMN–11, ''Risk-Informed Testing for Motor-Operated Valves.'' The NRC proposes to add four conditions in new §§ 50.55a(b)(3)(ii)(A), (B), (C), and (D) to address periodic verification of MOV design-basis capability. These conditions are discussed in the next four sections.

10 CFR 50.55a(b)(3)(ii)(A) MOV Diagnostic Test Interval

The NRC proposes to add § 50.55a(b)(3)(ii)(A) to require that licensees evaluate the adequacy of the diagnostic test interval for each MOV and adjust the interval as necessary, but not later than 5 years or three refueling outages (whichever is longer) from initial implementation of ASME OM Code, Appendix III. Paragraph III–3310(b) in Appendix III includes a provision stating that if insufficient data exist to determine the IST interval, then MOV inservice testing shall be conducted every two refueling outages or 3 years (whichever is longer) until sufficient data exist, from an applicable MOV or MOV group, to justify a longer IST interval. As discussed in 64 FR 51386 (September 22, 1999) with respect to the use of ASME OM Code Case OMN–1, the NRC considers it appropriate to include a modification requiring licensees to evaluate the information obtained for each MOV, during the first 5 years or three refueling outages (whichever is longer) of the use of Appendix III to validate assumptions made in justifying a longer test interval.

10 CFR 50.55a(b)(3)(ii)(B) MOV Testing Impact On Risk

The NRC proposes to add § 50.55a(b)(3)(ii)(B) to require that licensees ensure that the potential increase in core damage frequency (CDF) and large early release frequency (LERF) associated with the extension is acceptably small when extending exercise test intervals for high risk MOVs beyond a quarterly frequency. As discussed in 64 FR 51386 (September 22, 1999) with respect to the use of ASME OM Code Case OMN–1, the NRC considers it important for licensees to have sufficient information from the specific MOV, or similar MOVs, to demonstrate that exercising on a refueling outage frequency does not significantly affect component performance. The information may be obtained by grouping similar MOVs and establishing periodic exercising intervals of MOVs in the group over the refueling interval.

Section 50.55a(b)(3)(ii)(B) requires that the increase in the overall plant CDF and LERF resulting from the extension be acceptably small. As presented in RG 1.174, ''An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,'' the NRC considers acceptably small changes to be relative and to depend on the current plant CDF and LERF. For plants with total baseline CDF of 10^{-4} per year or less, acceptably small means CDF increases of up to 10^{-5} per year and for plants with total baseline CDF greater than 10^{-4} per year, acceptably small means CDF increases of up to 10^{-6} per year. For plants with total baseline LERF of 10^{-5} per year or less, acceptably small LERF increases are considered to be up to 10^{-6} per year, and for plants with total baseline LERF greater than 10^{-5} per year, acceptably small LERF increases are considered to be up to 10^{-7} per year.

10 CFR 50.55a(b)(3)(ii)(C) MOV Risk Categorization

The NRC proposes to add § 50.55a(b)(3)(ii)(C) to require, when applying Appendix III to the ASME OM Code, that licensees categorize MOVs according to their safety significance using the methodology described in ASME OM Code Case OMN–3, ''Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants,'' subject to the conditions discussed in RG 1.192, or using an MOV risk ranking methodology accepted by the NRC on a plant-specific or industry-wide basis in accordance with the conditions in the applicable safety evaluation. Paragraph III–3720 in Appendix III to the ASME OM Code states that when applying risk insights, each MOV shall be evaluated and categorized using a documented risk ranking methodology. Further, Appendix III only addresses risk ranking methodologies that include two risk categories. In light of the potential extension of quarterly test intervals for high risk MOVs and the relaxation of IST activities for low risk MOVs based on risk insights, the NRC has determined that the rule should specify that risk ranking methodologies must have been accepted by the NRC through RG 1.192 (which accepts ASME OM Code Case OMN–3 with the specified conditions) or safety evaluations issued to address plant-specific or industry-wide risk ranking methodologies.

Two conditions that were previously in RG 1.192 on the use of ASME OM Code Case OMN–11 related to application of the test interval criteria and grouping for low safety significant MOVs have been incorporated in an acceptable manner in Appendix III to the ASME OM Code. As noted in RG 1.192 on the use of ASME OM Code Case OMN–1, the benefits of performing a particular test should be balanced against the potential adverse effects placed on the valves or systems caused by this testing.

10 CFR 50.55a(b)(3)(ii)(D) MOV Stroke Time

The NRC proposes to add § 50.55a(b)(3)(ii)(D) to require that when a licensee applies Paragraph III–3600, ''MOV Exercising Requirements,'' of Appendix III to the OM Code, the licensee verify that the stroke time of the MOV satisfies the assumptions in the plant safety analyses. Previous editions and addenda of the ASME OM Code specified that the licensee must perform quarterly MOV stroke time measurements that could be used to verify that the MOV stroke time satisfies the assumptions in the safety analyses consistent with plant TS. The need for verification of the MOV stroke time during periodic exercising is consistent with the NRC's lessons learned from the implementation of ASME OM Code Case OMN–1. However, Paragraph III–3600 of Appendix III of the versions of the OM Code proposed to be incorporated by reference in this rulemaking no longer require the verification of MOV stroke time during periodic exercising. For this reason, the NRC is proposing to adopt the new condition which will effectively retain the need to verify MOV stroke time during periodic exercising.

10 CFR 50.55a(b)(3)(iii) OM condition: New Reactors

The NRC proposes to add § 50.55a(b)(3)(iii) to apply specific conditions for IST programs applicable to licensees of new nuclear power plants in addition to the provisions of the ASME OM Code as incorporated by reference with conditions in § 50.55a. Licensees of ''new reactors'' are, as identified in the proposed paragraph: (i) Holders of operating licenses for nuclear power reactors that received construction permits under this part on or after the date 12 months after the effective date of this rulemaking and (ii) holders of combined licenses (COLs) issued under 10 CFR part 52, whose initial fuel loading occurs on or after the date 12 months after the effective date of this rulemaking. This implementation schedule for new reactors is consistent with the NRC regulations in § 50.55a(f)(4)(i).

The NRC is evaluating COL applications to construct and operate nuclear power plants with certified designs under the process described in 10 CFR part 52. Commission Papers SECY–90–016, ''Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements;'' SECY–93–087, ''Policy, Technical, and Licensing Issues Pertaining to Evolutionary and

Advanced Light-Water Reactor (ALWR) Designs;'' SECY–94–084, ''Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs;'' and SECY–95–132, ''Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY–94–084),'' discuss IST programs for new reactors licensed under 10 CFR part 52.

In recognition of new reactor designs and lessons learned from nuclear power plant operating experience, the ASME is updating the OM Code to incorporate improved IST provisions for components used in nuclear power plants that were issued (or will be issued) construction permits, or COLs, on or following January 1, 2000 (defined in the ASME OM Code as post-2000 plants). The first phase of the ASME effort incorporated IST provisions that specify full flow pump testing and other clarifications for post-2000 plants in the ASME OM Code beginning with the 2011 Addenda. The second phase of the ASME effort incorporated preservice and inservice inspection and surveillance provisions for pyrotechnic-actuated (squib) valves in the 2012 Edition of the ASME OM Code. The ASME is considering further modifications to the ASME OM Code to address additional lessons learned from valve operating experience and new reactor issues. As described in the following paragraphs, § 50.55a(b)(3)(iii) will include four specific conditions.

10 CFR 50.55a(b)(3)(iii)(A) Power-Operated Valves

The NRC proposes to add § 50.55a(b)(3)(iii)(A) to require that licensees subject to § 50.55a(b)(3)(iii) develop a program to periodically verify the capability of power-operated valves (POVs) to perform their design-basis safety functions. While Appendix III to the ASME OM Code addresses this requirement for motor-operated valves (MOVs) with applicable conditions specified in § 50.55a, nuclear power plant licensees will need to develop programs to periodically verify the design-basis capability of other POVs. The NRC's Regulatory Issue Summary (RIS) 2000–03, ''Resolution of Generic Issue 158: Performance of Safety-Related Power-Operated Valves Under Design Basis Conditions,'' provides attributes for a successful long-term periodic verification program for POVs by incorporating lessons learned from MOV performance at operating nuclear power plants and during research programs. Implementation of Appendix III to the ASME OM Code as accepted in § 50.55a(b)(3)(ii) is acceptable in satisfying § 50.55a(b)(3)(iii)(A) for MOVs.

10 CFR 50.55a(b)(3)(iii)(B) Check Valves

The NRC proposes to add § 50.55a(b)(3)(iii)(B) to require that licensees subject to § 50.55a(b)(3)(iii) perform bi-directional testing of check valves within the IST program where practicable. Nuclear power plant operating experience has revealed that testing check valves in only the flow direction can result in significant degradation, such as a missing valve disc, not being identified by the test. Nonmandatory Appendix M, ''Design Guidance for Nuclear Power Plant Systems and Component Testing,'' to ASME OM Code, 2011 Addenda and 2012 Edition, includes guidance for the design of new reactors to enable bi-directional testing of check valves. New reactor designs will provide the capability for licensees of new nuclear power plants to perform bi-directional testing of check valves within the IST program.

10 CFR 50.55a(b)(3)(iii)(C) Flow-Induced Vibration

The NRC proposes to add § 50.55a(b)(3)(iii)(C) to require that licensees subject to § 50.55a(b)(3)(iii) monitor flow-induced vibration (FIV) from hydrodynamic loads and acoustic resonance during preservice testing and inservice testing to identify potential adverse flow effects that might impact components within the scope of the IST program. Nuclear power plant operating experience has revealed the potential for adverse flow effects from vibration caused by hydrodynamic loads and acoustic resonance on components in the reactor coolant, steam, and feedwater systems. Therefore, the licensee will need to address potential adverse flow effects on safety-related pumps, valves, and dynamic restraints within the IST program in the reactor coolant, steam, and feedwater systems from hydraulic loading and acoustic resonance during plant operation to confirm that piping, components, restraints, and supports have been designed to withstand the dynamic effects of steady-state FIV and anticipated operational transient conditions. The initial test program can be used to verify that safety-related piping and components are properly installed and supported such that vibrations caused by steady-state or dynamic effects do not result in excessive stress or fatigue in safety-related plant systems.

10 CFR 50.55a(b)(3)(iii)(D) High-Risk Non-Safety Systems

The NRC proposes to add § 50.55a(b)(3)(iii)(D) to require that licensees subject to § 50.55a(b)(3)(iii) establish a program to assess the operational readiness of pumps, valves, and dynamic restraints within the scope of the Regulatory Treatment of Non-Safety Systems (RTNSS) for applicable reactor designs. In SECY–94–084 and SECY–95–132, the Commission discusses RTNSS policy and technical issues associated with passive plant designs. Some new nuclear power plants have ALWR designs that use passive safety systems that rely on natural forces, such as density differences, gravity, and stored energy, to supply safety injection water and to provide reactor core and containment cooling. Active systems in passive ALWR designs are categorized as non-safety systems with limited exceptions. Active systems in passive ALWR designs provide the first line of defense to reduce challenges to the passive systems in the event of a transient at the nuclear power plant. Active systems that provide a defense-in-depth function in passive ALWR designs need not meet all of the acceptance criteria for safety-related systems. However, there should be a high level of confidence that these active systems will be available and reliable when challenged. The combined activities to provide confidence in the capability of these active systems in passive ALWR designs to perform their functions important to safety are referred to together as the RTNSS program. In a public memorandum dated July 24, 1995, the NRC staff provided a consolidated list of the approved policy and technical positions associated with RTNSS equipment in passive plant designs discussed in SECY–94–084 and SECY–95–132 (ADAMS Accession No. ML003708048). This new paragraph will specify the need for licensees to assess the operational readiness of RTNSS pumps, valves, and dynamic restraints.

10 CFR 50.55a(b)(3)(iv) OM Condition: Check Valves (Appendix II)

The NRC proposes to revise § 50.55a(b)(3)(iv) to address Appendix II, ''Check Valve Condition Monitoring Program,'' provided in the 2003 Addenda through the 2012 Edition of the ASME OM Code. In the 2003 Addenda of the ASME OM Code, ASME revised Appendix II to address the conditions specified in § 50.55a for older versions of the appendix. Therefore, the NRC considers Appendix

II in the 2003 Addenda through the 2012 Edition of the ASME OM Code to be acceptable for use without conditions. In accepting the recent versions of Appendix II, the NRC proposes to clarify that (1) the maximum test interval allowed by Appendix II for individual check valves in a group of two valves or more must be supported by periodic testing of a sample of check valves in the group during the allowed interval and (2) the periodic testing plan must be designed to test each valve of a group at approximate equal intervals not to exceed the maximum requirement interval. The NRC notes that ASME has provided additional improvements to Appendix II since issuance of the 2003 Addenda. Therefore, where a licensee plans to voluntarily implement Appendix II to the ASME OM Code, the licensee should apply Appendix II in the most recent addenda and edition of ASME OM Code incorporated by reference in § 50.55a. The conditions currently specified for the use of Appendix II, 1995 Edition with the 1996 and 1997 Addenda, and 1998 Edition through the 2002 Addenda, of the OM Code remain the same in this proposed rule.

10 CFR 50.55a(b)(3)(vii) OM Condition: Subsection ISTB

The NRC proposes to add § 50.55a(b)(3)(vii) to prohibit the use of Subsection ISTB, ''Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants,'' in the 2011 Addenda of the ASME OM Code. In the 2011 Addenda to the ASME OM Code, the upper end of the Acceptable Range and the Required Action Range for flow and differential or discharge pressure for comprehensive pump testing in Subsection ISTB was raised to higher values. The NRC staff on the ASME OM Code committee accepted the proposed increase of the upper end of the Acceptable Range and Required Action Range with the planned addition of a requirement for a pump periodic verification test program in the ASME OM Code. However, the 2011 Addenda to the ASME OM Code did not include the requirement for a pump periodic verification test program as an oversight. Since then, the 2012 Edition to the ASME OM Code has incorporated Mandatory Appendix V, ''Pump Periodic Verification Test Program,'' that supports the changes to the acceptable and required action ranges for comprehensive pump testing in Subsection ISTB. Therefore, proposed new § 50.55a(b)(3)(vii) would prohibit the use of Subsection ISTB in the 2011 Addenda of the ASME OM Code. Licensees will be allowed to apply Subsection ISTB with the revised acceptable and required action ranges in the 2012 Edition of the ASME OM Code as incorporated by reference in § 50.55a.

10 CFR 50.55a(b)(3)(viii) OM Condition: Subsection ISTE

The NRC proposes to add § 50.55a(b)(3)(viii) to specify that licensees proposing to implement Subsection ISTE, ''Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants,'' of the ASME OM Code, 2009 Edition, 2011 Addenda, and 2012 Edition, must request and obtain NRC authorization in accordance with § 50.55a(z) to apply Subsection ISTE on a plant-specific basis as a risk-informed alternative to the applicable IST requirements in the ASME OM Code.

In the 2009 Edition of the ASME OM Code, the ASME included new Subsection ISTE that describes a voluntary risk-informed approach in developing an IST program for pumps and valves at nuclear power plants. If a licensee chooses to implement this risk-informed IST approach, Subsection ISTE indicates that all requirements in Subsection ISTA, ''General Requirements,'' Subsection ISTB, and Subsection ISTC, ''Inservice Testing of Valves in Light-Water Reactor Nuclear Power Plants,'' of the ASME OM Code continue to apply, except those identified in Subsection ISTE. The ASME selected risk-informed guidance from ASME OM Code Cases OMN–1, OMN–3, OMN–4, ''Requirements for Risk Insights for Inservice Testing of Check Valves at LWR Power Plants,'' OMN–7, ''Alternative Requirements for Pump Testing,'' OMN–11, and OMN–12, ''Alternative Requirements for Inservice Testing Using Risk Insights for Pneumatically and Hydraulically Operated Valve Assemblies in Light-Water Reactor Power Plants,'' in preparing Subsection ISTE of the ASME OM Code.

During development of Subsection ISTE, the NRC staff participating on the ASME OM Code committees indicated that the conditions specified in RG 1.192 for the use of the applicable ASME OM Code Cases need to be considered when evaluating the acceptability of the implementation of Subsection ISTE. In addition, the NRC staff noted that several aspects of Subsection ISTE will need to be addressed on a case-by-case basis when determining the acceptability of its implementation. Therefore, new § 50.55a(b)(3)(viii) requires that licensees proposing to implement Subsection ISTE of the ASME OM Code must request approval from the NRC to apply Subsection ISTE on a plant-specific basis as a risk-informed alternative to the applicable IST requirements in the ASME OM Code.

Nuclear power plant applicants for construction permits under 10 CFR part 50, or combined licenses for construction and operation under 10 CFR part 52, may describe their proposed implementation of the risk-informed IST approach specified in Subsection ISTE of the ASME OM Code for NRC review in their applications.

The NRC will evaluate § 50.55a(z) requests for approval to implement Subsection ISTE in accordance with the following considerations:

1. Scope of Risk-Informed IST Program

Subsection ISTE–1100, ''Applicability,'' establishes the component safety categorization methodology and process for dividing the population of pumps and valves, as identified in the IST Program Plan, into high safety significant component (HSSC) and low safety significant component (LSSC) categories. When establishing a risk-informed IST program, the licensee should address a wide range of components important to safety at the nuclear power plant that includes both safety-related and nonsafety-related components. These components might extend beyond the scope of the ASME OM Code.

2. Risk-Ranking Methodology

The licensee should specify in its request for authorization to implement a risk-informed IST program the methodology to be applied in risk ranking its components. ISTE–4000, ''Specific Component Categorization Requirements,'' incorporates ASME OM Code Case OMN–3 for the categorization of pumps and valves in developing a risk-informed IST program. The OMN–3 Code Case methodology for risk ranking uses two categories of safety significance. The NRC staff has also accepted other methodologies for risk ranking that use three categories of safety significance.

3. Safety Significance Categorization

The licensee should categorize components according to their safety significance based on the methodology described in Subsection ISTE with the applicable conditions on the use of ASME OM Code Case OMN–3 specified in RG 1.192, or use other risk ranking methodologies accepted by the NRC on a plant-specific or industry-wide basis with applicable conditions specified by the NRC for their acceptance. The licensee should address the seven conditions in RG 1.192 for the use of ASME OM Code Case OMN–3 as appropriate in developing the risk-informed IST program described in Subsection ISTE. With respect to the provisions in Subsection ISTE, these conditions are:

(a) The implementation of ISTE–1100 should include within the scope of a licensee's risk-informed IST program non-ASME Code pumps and valves categorized as HSSCs that might not currently be included in the IST program at the nuclear power plant.

(b) The decision criteria discussed in ISTE–4410, ''Decision Criteria,'' and Non-mandatory Appendix L, ''Acceptance Guidelines,'' of the ASME OM Code for evaluating the acceptability of aggregate risk effects (*i.e.,* for Core Damage Frequency [CDF] and Large Early Release Frequency [LERF]) should be consistent with the guidance provided in RG 1.174, ''An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis.''

(c) The implementation of ISTE–4440, ''Defense in Depth,'' should be consistent with the guidance contained in Section 2.2.1, ''Defense-in-Depth Evaluation,'' and Section 2.2.2, ''Safety Margin Evaluation,'' of RG 1.175, ''An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing.''

(d) The implementation of ISTE–4500, ''Inservice Testing Program,'' and ISTE–6100, ''Performance Monitoring,'' should be consistent with the guidance contained in Section 3.2, ''Program Implementation,'' and Section 3.3, ''Performance Monitoring,'' of RG 1.175.

(e) The implementation of ISTE–3210, ''Plant-Specific PRA,'' should be consistent with the guidance that the Owner is responsible for demonstrating and justifying the technical adequacy of the PRA analyses used as the basis to perform component risk ranking and for estimating the aggregate risk impact. For example, RG 1.200, ''An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,'' and RG 1.201, ''Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants According to their Safety Significance,'' provide guidance for PRA technical adequacy and component risk ranking.

(f) The implementation of ISTE–4240, ''Reconciliation,'' should specify that the expert panel may not classify components that are ranked HSSC by the results of a qualitative or quantitative PRA evaluation (excluding the sensitivity studies) or the defense-in-depth assessment to LSSC.

(g) The implementation of ISTE–3220, ''Living PRA,'' should be consistent with the following: (i) To account for potential changes in failure rates and other changes that could affect the PRA, changes to the plant must be reviewed and, as appropriate, the PRA updated; (ii) when the PRA is updated, the categorization of structures, systems, and components must be reviewed and changed if necessary to remain consistent with the categorization process; and (iii) the review of the plant changes must be performed in a timely manner and must be performed once every two refueling outages, or as required by § 50.71(h)(2) for COL holders.

4. Pump Testing

Subsection ISTE–5100, ''Pumps,'' incorporates ASME OM Code Case OMN–7 for risk-informed testing of pumps categorized as LSSCs. Subsection ISTE–5100 allows the interval for Group A and Group B testing of LSSC pumps specified in Subsection ISTB of the ASME OM Code to be extended from the current 3-month interval to intervals of 6 months or 2 years. Subsection ISTE–5100 eliminates the requirement in Subsection ISTB to perform comprehensive pump testing for LSSC pumps. Table ISTE–5121–1, ''LSSC Pump Testing,'' specifies that pump operation may be required more frequently than the specified test frequency (6 months) to meet vendor recommendations. Subsection ISTE–4500, ''Inservice Testing Program,'' specifies in ISTE–4510, ''Maximum Testing Interval,'' that the maximum testing interval shall be based on the more limiting of (a) the results of the aggregate risk, or (b) the performance history of the component. ISTE–5130, ''Maximum Test Interval—Pre-2000 Plants,'' specifies that the most limiting interval for LSSC pump testing shall be determined from ISTE–4510 and ISTE–5120, ''Low Safety Significant Pump Testing.'' The ASME developed the comprehensive pump test requirements in the ASME OM Code to address weaknesses in the Code requirements to assess the operational readiness of pumps to perform their design-basis safety function. Therefore, the licensee should ensure that testing under Subsection ISTE will provide assurance of the operational readiness of pumps in each safety significant categorization to perform their design-basis safety function as described in RGs 1.174 and 1.175.

5. Motor-Operated Valve Testing

Subsection ISTE–5300, ''Motor Operated Valve Assemblies,'' provides a risk-informed IST approach instead of the IST requirements for MOVs in Mandatory Appendix III to the ASME OM Code. The ASME prepared Appendix III to the OM Code to replace the requirement for quarterly stroke-time testing of MOVs with a program of periodic exercising and diagnostic testing to address lessons learned from nuclear power plant operating experience and industry and regulatory research programs for MOV performance. Subsection ISTC of the ASME OM Code specifies the implementation of Appendix III for periodic exercising and diagnostic testing of MOVs to replace quarterly stroke-time testing previously required for MOVs. Appendix III incorporates provisions that allow a risk-informed IST approach for MOVs as described in ASME OM Code Cases OMN–1 and OMN–11. Subsection ISTE–5300 is not consistent with the provisions for the risk-informed IST program for MOVs specified in Appendix III to the ASME OM Code (and Code Cases OMN–1 and 11). Therefore, licensees proposing to implement Subsection ISTE should address the provisions in paragraph III–3700, ''Risk-Informed MOV Inservice Testing,'' of Appendix III to the ASME OM Code as incorporated by reference in § 50.55a with the applicable conditions instead of ISTE–5300.

6. Pneumatically and Hydraulically Operated Valve Testing

Subsection ISTE–5400, ''Pneumatically and Hydraulically Operated Valves,'' specifies that licensees test their AOVs and HOVs in accordance with Appendix IV to the ASME OM Code. Subsection ISTE–5400 indicates that Appendix IV is in the course of preparation. The NRC staff will need to review Appendix IV prior to accepting its use as part of Subsection ISTE. Therefore, licensees proposing to implement Subsection ISTE should describe the planned IST provisions for AOVs and HOVs in its request for authorization to implement Subsection ISTE.

7. Pump Periodic Verification Test

Subsection ISTE does not include a requirement to implement the pump periodic verification test program specified in Mandatory Appendix V to the ASME OM Code, 2012 Edition. The licensee should address the consideration of a pump periodic verification test program in its risk-informed IST program proposed as part of the authorization request to implement Subsection ISTE.

10 CFR 50.55a(b)(3)(ix) OM Condition: Subsection ISTF

The NRC proposes to add § 50.55a(b)(3)(ix) for two purposes. First, the proposed condition specifies that licensees applying Subsection ISTF, ''Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants—Post-2000 Plants,'' in the 2012 Edition of the OM Code shall satisfy the requirements of Mandatory Appendix V, ''Pump Periodic Verification Test Program,'' of the OM Code, 2012 Edition. The proposed condition also states that Subsection ISTF, 2011 Addenda, is not acceptable for use. As previously discussed regarding new § 50.55a(b)(3)(vii), the upper end of the Acceptable Range and the Required Action Range for flow and differential or discharge pressure for comprehensive pump testing in Subsection ISTB in the ASME OM Code was raised to higher values in combination with the incorporation of Mandatory Appendix V, ''Pump Periodic Verification Test Program.'' However, Subsection ISTF in the 2011 Addenda and 2012 Edition to the ASME OM Code does not include a requirement for a pump periodic verification test program. Therefore, new § 50.55a(b)(3)(ix) would require that the provisions of Appendix V be applied when implementing Subsection ISTF of the 2012 Edition of the OM Code to support the application of the upper end of the Acceptable Range and the Required Action Range for flow and differential or discharge pressure for inservice pump testing in Subsection ISTF. The proposed paragraph would prohibit the use of Subsection ISTF in the 2011 Addenda of the OM Code, which does not include Appendix V.

10 CFR 50.55a(b)(3)(xi) OM Condition: Valve Position Indication

The NRC proposes to add a new paragraph, § 50.55a(b)(3)(xi), containing a new condition that would specify that when implementing ASME OM Code, Subsection ISTC–3700, ''Position Verification Testing,'' licensees shall supplement the ASME OM Code provisions as necessary to verify that valve operation is accurately indicated. Subsection ISTC–3700 of the ASME OM Code requires that valves with remote position indicators shall be observed locally at least once every 2 years to verify that valve operation is accurately indicated. Subsection ISTC–3700 states that where practicable, this local observation should be supplemented by other indications such as the use of flow meters or other suitable instrumentation to verify obturator position. Subsection ISTC–3700 also states that where local observation is not possible, other indications shall be used for verification of valve operation. Nuclear power plant operating experience has revealed that reliance on indicating lights and stem travel are not sufficient to satisfy the requirement in ISTC–3700 to verify that valve operation is accurately indicated. Appendix A, ''General Design Criteria for Nuclear Power Plants,'' to 10 CFR part 50 requires that where generally recognized codes and standards are used, they shall be identified and evaluated to determine their applicability, adequacy, and sufficiency, and shall be supplemented or modified as necessary to assure a quality product in keeping with the required safety function. This new condition specifies that when implementing ASME OM Code, Subsection ISTC–3700, licensees shall develop and implement a method to verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications, such as flow meters or other suitable instrumentation, to provide assurance of proper obturator position. This is not a new requirement but rather a clarification of the intent of the existing ASME OM Code. The ASME OM Code specifies obturator movement verification in order to detect certain internal valve failure modes consistent with the definition of 'exercising' found in ISTA–2000 (*i.e.,* demonstration that the moving parts of a component function). Verification of the ability of an obturator to change or maintain position is an essential element of valve operational readiness determination which is a fundamental aspect of the ASME OM Code. The NRC's position is further elaborated in NUREG–1482 Revision 2, paragraph 4.2.7.

10 CFR 50.55a(f): Inservice Testing Requirements

The NRC proposes to revise the introductory text of § 50.55a(f) to indicate that systems and components must meet the requirements for ''preservice and inservice testing'' in the applicable ASME Codes and that both activities are referred to as ''inservice testing'' in the remainder of paragraph (f). The proposed change clarifies that the ASME OM Code includes provisions for preservice testing of components as part of its overall provisions for IST programs. No expansion of IST program scope is intended by this clarification.

10 CFR 50.55a(f)(3)(iii)(A) Class 1 Pumps and Valves: First Provision

The NRC proposes to revise § 50.55a(f)(3)(iii)(A) to ensure that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. Paragraph ISTA–1100, ''Scope,'' in Subsection ISTA, ''General Requirements,'' of the ASME OM Code states that the requirements for preservice and inservice testing and examination of components in light-water reactor nuclear power plants apply to (a) pumps and valves that are required to perform a specific function in shutting down a reactor to the safe shutdown condition, in maintaining the safe shutdown condition, or in mitigating the consequences of an accident; (b) pressure relief devices that protect systems or portions of systems that perform one or more of these three functions; and (c) dynamic restraints (snubbers) used in systems that perform one of more of these three functions, or to ensure the integrity of the reactor coolant pressure boundary. This revision will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6, ''Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints.''

10 CFR 50.55a(f)(3)(iii)(B) Class 1 Pumps and Valves: Second Provision

The NRC proposes to revise § 50.55a(f)(3)(iii)(B) to clarify that this paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This revision will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(3)(iv)(A) Class 2 and 3 Pumps and Valves: First Provision

The NRC proposes to revise § 50.55a(f)(3)(iv)(A) to clarify that this paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(A) for Class 1 pumps and valves. This revision will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(3)(iv)(B) Class 2 and 3 Pumps and Valves: Second Provision

The NRC proposes to revise § 50.55a(f)(3)(iv)(B) to clarify that this paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(B) for Class 1 pumps and valves. This revision will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(4) Inservice Testing Standards Requirement for Operating Plants

The NRC proposes to revise § 50.55a(f)(4) to clarify that this paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This revision will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6.

D. ASME Code Cases

The NRC proposes to remove the revision number of the three RGs currently approved by the Office of the Federal Register for incorporation by reference throughout the substantive provisions of § 50.55a. The revision numbers for the RGs approved for incorporation by reference (currently, RGs 1.84, 1.147, and 1.192) would be retained in paragraph (a)(3)(i) through (a)(3)(iii) of § 50.55a, where the RGs are listed by full title, including revision number. These proposed changes would simplify the regulatory language containing cross-references to these RGs and reduce the possibility of NRC error in preparing future amendments to § 50.55a with respect to these RGs. These changes are administrative in nature and do not change substantive requirements with respect to the RGs and the Code Cases listed in the RGs.

ASME BPV Code Case N–729–4

On September 10, 2008, the NRC issued a final rule to update § 50.55a to the 2004 Edition of the ASME Code (73 FR 52730). As part of the final rule, § 50.55a(g)(6)(ii)(D) implemented an augmented inservice inspection program for the examination of reactor pressure vessel (RPV) upper head penetration nozzles and associated partial penetration welds. The program required the implementation of ASME BPV Code Case N–729–1, with certain conditions.

The application of ASME BPV Code Case N–729–1 was necessary because the inspections required by the 2004 Edition of the ASME BPV Code, Section XI were not written to address degradation of the RPV upper head penetration nozzles welds by primary water stress corrosion cracking (PWSCC). The safety consequences of inadequate inspections can be significant. The NRC's determination that the ASME Code required inspections are inadequate is based upon operating experience and analysis. The absence of an effective inspection regime could, over time, result in unacceptable circumferential cracking, or the degradation of the RPV upper head or other reactor coolant system components by leakage assisted corrosion. These degradation mechanisms increase the probability of a loss-of-coolant accident.

Examination frequencies and methods for RPV upper head penetration nozzles and welds are provided in ASME BPV Code Case N–729–1. The use of code cases is voluntary, so these provisions were developed, in part, with the expectation that the NRC would incorporate the code case by reference into the CFR. Therefore, the NRC adopted rule language in § 50.55a(g)(6)(ii)(D) requiring implementation of ASME BPV Code Case N–729–1, with conditions, in order to enhance the examination requirements in the ASME BPV Code, Section XI for RPV upper head penetration nozzles and welds. The examinations conducted in accordance with ASME BPV Code Case N–729–1 provide reasonable assurance that ASME Code allowable limits will not be exceeded and that PWSCC will not lead to failure of the RPV upper head penetration nozzles or welds. However, the NRC concluded that certain conditions were needed in implementing the examinations in ASME BPV Code Case N–729–1. These conditions are set forth in § 50.55a(g)(6)(ii)(D).

On June 22, 2012, the ASME approved the fourth revision of ASME BPV Code Case N–729, (N–729–4). This revision changed certain requirements based on a consensus review of inspection techniques and frequencies. These changes were deemed necessary by the ASME to supersede the previous requirements under N–729–1 to establish an effective long-term inspection program for the RPV upper head penetration nozzles and associated welds in pressurized water reactors. The major changes included incorporation of previous NRC conditions in the CFR. Minor changes were also made to address editorial issues, to correct figures or to add clarity.

The NRC proposes to update the requirements of § 50.55a(g)(6)(ii)(D) to require licensees to implement ASME BPV Code Case N–729–4, with conditions. The NRC conditions have been modified to address the changes in ASME BPV Code Case N–729–4. The NRC's proposed revisions to the conditions on ASME BPV Code Case N–729–1 are discussed in the next four sections.

10 CFR 50.55a(g)(6)(ii)(D)(1) Implementation

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*1*) to change the version of ASME BPV Code Case N–729 from N–729–1 to N–729–4 for the reasons previously set forth. Due to the incorporation of N–729–4, the date to establish applicability for licensed pressurized water reactors will be changed to the effective date of the final rule.

10 CFR 50.55a(g)(6)(ii)(D)(2) Through (6)

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*2*) through (*6*) to remove the conditions currently in § 50.55a(g)(6)(ii)(D)(*2*) through (*5*) and to redesignate the condition currently in § 50.55a(g)(6)(ii)(D)(*6*) as § 50.55a(g)(6)(ii)(D)(*2*). The conditions currently in § 50.55a(g)(6)(ii)(D)(*2*) to § 50.55a(g)(6)(ii)(D)(*5*) have all been incorporated either verbatim or more conservatively in the revisions to ASME BPV Code Case N–729, up to version N–729–4. Therefore, there is no reason to retain these conditions in § 50.55a. The NRC proposes to include new conditions in § 50.55a(g)(6)(ii)(D)(*3*) and (*4*) as described in the following discussion.

10 CFR 50.55a(g)(6)(ii)(D)(3) Bare Metal Visual Frequency

The NRC proposes to adopt a new condition (to be included in proposed § 50.55a(g)(6)(ii)(D)(*3*)) to modify the option to extend bare metal visual inspections of the reactor pressure vessel upper head surface beyond the frequency listed in Table 1 of ASME BPV Code Case N–729–4. Previously, upper heads aged with less than eight effective degradation years were considered to have a low probability of initiating PWSCC, the cracking mechanism of concern. This ranking of effective degradation years was based on a simple time at temperature correlation. All of the upper heads within this category, with the exception of new heads using Alloy 600 penetration nozzles, were considered to have lower susceptibility to cracking due to the upper heads being at or near the cold leg operating temperature of the reactor coolant system. Therefore, these plants were said to have ''cold heads.'' All of the upper heads that had experienced cracking prior to 2006 were near the hot leg operating temperature of the reactor coolant system, which validated the time at temperature model.

In 2006, one of the 21 ''cold head'' plants identified two indications within a penetration nozzle and the associated partial penetration weld. Then, between 2006 and 2013, five of the 21 ''cold head'' plants identified multiple indications within fifteen different penetration nozzles and the associated partial penetration welds. None of these indications caused leakage, and volumetric examination of the penetration nozzles showed no flaw in the nozzle material had grown through-wall; however, this increasing trend creates a reasonable safety concern.

Recent operational experience has shown that the volumetric inspection of penetration nozzles, at the current inspection frequency, is adequate to identify indications in the nozzle material prior to leakage; however, volumetric examinations cannot be performed on the partial penetration welds. Therefore, given the additional cracking identified at cold leg temperature, the NRC staff has concerns about the adequacy of the partial penetration weld examinations.

Leakage from a partial penetration weld into the annulus between the nozzle and head material can cause corrosion of the low alloy steel head. While initially limited in leak rate, due to limited surface area of the weld being in contact with the annulus region, corrosion of the vessel head material can expose more of the weld surface to the annulus, allowing a greater leak rate. Since an indication in the weld cannot be identified by a volumetric inspection, a postulated crack through the weld, just about to cause leakage, could exist as a plant performed its last volumetric and/or bare metal visual examination of the upper head material. This gives the crack years to breach the surface and leak prior to the next scheduled visual examination.

Only a surface examination of the wetted surface of the partial penetration weld can reliably detect flaws in the weld. Unfortunately, this examination cannot size the flaws in the weld, and, if performed manually, requires significant radiological dose to examine all the partial penetration welds on the upper head. As such, the available techniques are only able to detect a flaw after it has caused leakage. These techniques are a bare metal visual examination or a volumetric leak path assessment performed on the frequency of the volumetric examination.

Volumetric leak path examinations are only done on outages when a volumetric examination of the nozzle is performed. Therefore, under the current requirements allowed by Note 4 of ASME BPV Code Case N–729–4, leakage from a crack in the weld of a ''cold head'' plant could start and continue to grow for the 5 years between the required bare metal visual examinations to detect leakage through the partial penetration weld.

Given the additional cracking identified at cold leg temperature of upper head penetration nozzles and associated welds, the NRC finds limited basis to continue to categorize these ''cold head'' plants as having a low susceptibility to crack initiation. The NRC proposes to increase the frequency of the bare metal visual examinations of ''cold heads'' to identify potential leakage as soon as reasonably possible because of the volumetric examination limitations. Therefore, the NRC proposes to condition Note 4 of ASME BPV Code Case N–729–4 to require a bare metal visual exam each outage in which a volumetric exam is not performed. The NRC also proposes to allow ''cold head'' plants to extend their bare metal visual inspection frequency from once each refueling outage, as stated in Table 1 of N–729–1, to once every 5 years, but only if the licensee performed a wetted surface examination of all of the partial penetration welds during the previous volumetric examination. Applying the conditioned bare metal visual inspection frequency or a volumetric examination each outage will allow licensees to identify any potential leakage through the partial penetration welds prior to significant degradation of the low alloy steel head material, thereby providing reasonable assurance of the structural integrity of the reactor coolant pressure boundary.

These issues, including the operational experience, the fact that volumetric examination is not available to interrogate the partial penetration welds, and potential regulatory options, were discussed publicly at multiple ASME Code meetings, at the annual Materials Programs Technical Information Exchange public meeting held at the NRC Headquarters in June 2013, and at the 2013 NRC Regulatory Information Conference.

10 CFR 50.55a(g)(6)(ii)(D)(4) Surface Exam Acceptance Criteria

The NRC proposes to adopt a new condition (to be included in proposed § 50.55a(g)(6)(ii)(D)(*4*)) to define surface examination acceptance criteria. Paragraph –3132(b) of ASME BPV Code Case N–729–4 sets forth the acceptance criteria for surface examinations. In general, throughout Section XI of the ASME BPV Code, the acceptance criteria for surface examinations default to Section III, Paragraph NB–5352, ''Acceptance Standards''. Typically, for rounded indications, the indication was only unacceptable if it was greater than 3⁄16 inch in size. The NRC requested that the code case authors include a requirement that any size rounded indication causing nozzle leakage is unacceptable due to operating experience identifying PWSCC under rounded indications less than 3⁄16 inch in size.

Recently, the ASME Code Committee approved an interpretation of the language in Paragraph –3132(b) that implied any size rounded indication is acceptable unless there is relevant indication of nozzle leakage, even those greater than 3⁄16 inch. The NRC does not agree with the interpretation and maintains its original stance on rounded indications that any size rounded indication is unacceptable if there is an indication of leakage. Since the adoption of ASME BPV Code Case N–729–1 into § 50.55a(g)(6)(ii)(D), all licensees have used the NRC's stance in implementing Paragraph –3132(b), even after the recent ASME Code Committee interpretation approval over NRC objection.

Therefore, in order to ensure compliance with the previous and ongoing requirement, the NRC proposes to revise condition § 50.55a(g)(6)(ii)(D)(*4*) to include clarity within the acceptance criteria for surface examinations. The current edition requirements of NB–5352 of ASME BPV Code, Section III for the licensee's ongoing 10-year inservice inspection interval shall be met.

ASME BPV Code Case N–770–2

On June 21, 2011, the NRC issued a final rule including § 50.55a(g)(6)(ii)(F) requiring the implementation of ASME BPV Code Case N–770–1, ''Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS N86182 Weld Filler Material With or Without Application of Listed Mitigation Activities,'' with certain conditions.

On June 9, 2011, the ASME approved the second revision of ASME BPV Code Case N–770 (N–770–2). The major changes from N–770–1 to N–770–2 included establishing new ASME Code Case Table 1 inspection item classifications for optimized weld overlays and allowing alternatives when complete inspection coverage cannot be met. Minor changes were also made to address editorial issues, to correct figures, or to add clarity. The NRC finds that the updates and improvements in N–770–2 are sufficient to update § 50.55a(g)(6)(ii)(F).

The NRC therefore proposes to update the requirements of § 50.55a(g)(6)(ii)(F) to require licensees to implement ASME BPV Code Case N–770–2 with conditions. The NRC conditions have been modified to address the changes in ASME BPV Code Case N–770–2 and to ensure that this regulatory framework will provide adequate protection of public health and safety. The following sections discuss each of the NRC's proposed changes to the conditions on ASME BPV Code Case N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(1) Implementation

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*1*) to change the version of ASME BPV Code Case N–770 from N–770–1 to N–770–2 and to require its implementation (with conditions) to incorporate the updates and improvements contained in N–770–2. The NRC proposes that licensees begin using N–770–2 on the effective date of this rule.

10 CFR 50.55a(g)(6)(ii)(F)(2) Categorization

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*2*) to provide clarification regarding categorization of each Alloy 82/182 butt weld, mitigated or not, under N–770–2. This paragraph also clarifies the NRC's position that paragraph –1100(e) shall not be used to exempt welds that rely on Alloy 82/182 for structural integrity from more frequent ISI schedules until the NRC has reviewed and authorized an alternative categorization for the weld. Additionally, the NRC proposes to change the inspection item categories for full structural weld overlays from C to C–1 and F to F–1 due to reclassification under ASME BPV Code Case N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(3) Baseline Examinations

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*3*) to clarify the baseline examination requirements by stating that previously-conducted examinations, in order to count as baseline examinations, must meet the requirements of ASME BPV Code Case N–770–2, as conditioned. The 2011 rule required the use of ASME Code Section XI Appendix VIII qualifications for baseline examinations, which is stricter than N–770–2 and does not provide requirements for optimized weld overlays. The revision also updates the deadline for baseline examination requirements since the January 20, 2012, deadline from the previous rule has passed. Finally, upon implementation of this rule, if a licensee is currently in an outage, then the baseline inspection requirement can be met by performing the inspections in accordance with the current regulatory requirements of § 50.55a(g)(6)(ii)(F) in lieu of the examination requirements of paragraphs –2500(a) or –2500(b) of ASME BPV Code Case N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(4) Examination Coverage

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*4*) to define examination coverage for circumferential flaws and to prohibit the use of paragraph –2500(d) of ASME BPV Code Case N–770–2 which, in some circumstances, allows unacceptably low examination coverage. Paragraph –2500(d) of N–770–2 would allow the reduction of circumferential volumetric examination coverage with analytical evaluation. Paragraph –2500(c) was previously prohibited from use, and it continues to be prohibited. The NRC proposes to establish an essentially 100 percent volumetric examination coverage requirement for circumferential flaws to provide reasonable assurance of structural integrity of all ASME Code Class 1 butt welds susceptible to PWSCC. Therefore, the NRC proposes to adopt a condition prohibiting the use of paragraphs –2500(c) and –2500(d). A licensee may request approval for use of these paragraphs under 10 CFR 50.55a(z).

10 CFR 50.55a(g)(6)(ii)(F)(5) Inlay/Onlay Inspection Frequency

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*5*) to add the explanatory heading, ''Inlay/onlay inspection frequency,'' and to make minor editorial corrections.

10 CFR 50.55a(g)(6)(ii)(F)(6) Reporting Requirements

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*6*) to add the explanatory heading, ''Reporting requirements.''

10 CFR 50.55a(g)(6)(ii)(F)(7) Defining ''t''

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*7*) to add the explanatory heading, ''Defining 't'.''

10 CFR 50.55a(g)(6)(ii)(F)(8) Optimized Weld Overlay Examination

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*8*) to maintain the requirement for the timing of the initial inservice examination of optimized weld overlays. Uncracked welds mitigated with optimized weld overlays were re-categorized by ASME BPV Code Case N–770–2 from Inspection Item D to Inspection Item C–2; however, the initial inspection requirement was not incorporated into the Code Case for Inspection Item C–2.

The NRC has determined that uncracked welds mitigated with an optimized weld overlay must have an initial inservice examination no sooner than the third refueling outage and no later than 10 years following the application of the weld overlay to identify unacceptable crack growth. Optimized weld overlays establish compressive stress on the inner half thickness of the weld, but the outer half thickness may also be under tensile stresses. The requirement for an initial inservice examination no sooner than the third refueling outage and no later than 10 years following the application of the weld overlay is based on the design of optimized weld overlays which require the outer quarter thickness of the susceptible material to provide structural integrity for the weld. Therefore, the NRC proposes to continue adoption of the condition which requires the initial inservice examination of uncracked welds mitigated by optimized weld overlay (*i.e.,* the welds which are subject to Inspection Item C–2 of ASME BPV Code Case N–770–2) within the specified timeframe.

10 CFR 50.55a(g)(6)(ii)(F)(9) Deferral

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*9*) to address changes in ASME BPV Code Case N–770–2 which allow the deferral of the first inservice examination of uncracked welds mitigated with optimized weld overlays, Inspection Item C–2. Previously, under N–770–1, the initial inservice examination of these welds was not allowed to be deferred. Allowing deferral of the initial inservice examination in accordance with N–770–2 could, in certain circumstances, allow the initial inservice examination to be performed up to 20 years after installation. Therefore, the NRC proposes to adopt a condition which would preclude the deferral of the initial inservice examination of uncracked welds mitigated by optimized weld overlays.

10 CFR 50.55a(g)(6)(ii)(F)(10) Examination Technique

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*10*) to address changes in ASME BPV Code Case N–770–2. Note 14(a) of Table 1 of ASME BPV Code Case N–770–2 provides the previously required full examination requirement for optimized weld overlays. The language of ASME BPV Code Case N–770–2, however, does not require the implementation of the full examination requirements of Note 14(a) of Table 1, if possible, before implementing the reduced examination coverage requirements of Note 14(b) of Table 1 or Note (b) of Figure 5(a). The full examination requirement should be implemented, if possible, before the option of reduced examination coverage is allowed. Therefore, the NRC proposes to modify the current condition in § 50.55a(g)(6)(ii)(F)(*10*) to allow the use of Note 14(b) of Table 1 and Note (b) of Figure 5(a) of ASME BPV Code Case N–770–2 only after the determination that the requirements of Note 14(a) of Table 1 of ASME BPV Code Case N–770–2 cannot be met.

10 CFR 50.55a(g)(6)(ii)(F)(11) Cast Stainless Steel

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(*11*) to address examination requirements through cast stainless steel materials by requiring the use of Appendix VIII qualifications to meet the inspection requirements of paragraph –2500(a) of ASME BPV Code Case N–770–2. The requirements for volumetric examination of butt welds through cast stainless steel materials are currently being developed as Supplement 9 to the ASME BPV Code, Section XI, Appendix VIII. In accordance with Appendix VIII for supplements that have not been developed, the requirements of Appendix III apply. Appendix III requirements are not equivalent to Appendix VIII requirements. For the volumetric examination of ASME Class 1 welds, the NRC has established the requirement for examination qualification under the Appendix VIII. Thus, the NRC proposes to adopt a condition requiring the use of Appendix VIII qualifications to meet the inspection requirements of paragraph –2500(a) of ASME BPV Code Case N–770–2 by January 1, 2020.

The development of a sufficient number of mockups would be required to establish an Appendix VIII program for examination of ASME Code Class 1 piping and vessel nozzle butt welds through cast stainless steel materials. The NRC recognizes that significant time and resources are required to create mockups and to allow for qualification of equipment, procedures and personnel. Therefore, the NRC proposes that licensees be required to use these Appendix VIII qualifications no later than their first scheduled weld examinations involving cast stainless steel materials occurring after January 1, 2020.

10 CFR 50.55a(g)(6)(ii)(F)(12) Stress Improvement Inspection Coverage

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(*12*) to clarify the examination coverage requirements allowed under Appendix I of ASME BPV Code Case N–770–2 for butt welds joining cast stainless steel material. Under current ASME BPV Code, Section XI, Appendix VIII requirements, the volumetric examination of butt welds through cast stainless steel materials is under Supplement 9. Supplement 9 rules are still being developed by the ASME BPV Code. Therefore, it is currently impossible to meet the requirement of Paragraph I.5.1 for butt welds joining cast stainless steel material.

The material of concern is the weld material susceptible to PWSCC adjoining the cast stainless steel material. Appendix VIII qualified procedures are available to perform the inspection of the susceptible weld material, but they are not qualified to inspect the cast stainless steel materials. Therefore, the NRC proposes to adopt a condition changing the inspection volume for stress-improved dissimilar metal welds with cast stainless steel from the ASME Code Section XI requirements to ''the maximum extent practical including 100 percent of the susceptible material volume.'' This will remain applicable until an Appendix VIII qualified procedure for the inspection through cast stainless steel materials is available in accordance with the proposed condition in § 50.55a(g)(6)(ii)(F)(*11*).

10 CFR 50.55a(g)(6)(ii)(F)(13) Encoded Ultrasonic Examination

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(13) to require the encoding of ultrasonic volumetric examinations of Inspection Items A–1, A–2, B, E, F–2, J, and K in Table 1 of N–770–2. A human performance gap has been found between some ultrasonic testing procedures as demonstrated during ASME BPV Code, Section XI, Appendix VIII qualification versus as applied in the field.

The human factors that contributed to the recent examinations that failed to identify significant flaws at North Anna Power Station, Unit 1, in 2012 (Licensee Event Report 50–338/2012–001–00, ADAMS Accession No. ML12151A441) and at Diablo Canyon Nuclear Power Plant in 2013 (Relief Request REP–1 U2, Revision 2, ADAMS Accession No. ML13232A308) can be avoided by the use of encoded ultrasonic examinations. Encoded ultrasonic examinations electronically store both the positional and ultrasonic information from the inspections. Encoded examinations allow for the inspector to evaluate the data and search for indications outside of a time limiting environment to assure that the inspection was conducted properly and to allow for sufficient time to analyze the data. Additionally, the encoded examination would allow for an independent review of the data by other inspectors or an independent third party. Finally, the encoded examination could be compared to previous and/or future encoded examinations to determine if flaws are present and flaw growth rate. Therefore, the NRC proposes to adopt a condition requiring the use of encoding for ultrasonic volumetric examinations of non-mitigated or cracked mitigated dissimilar metal butt welds in the reactor coolant pressure boundary which are within the scope of ASME BPV Code Case N–770–2.

ASME BPV Code Case N–824

10 CFR 50.55a(b)(2)(xxxvii) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii) to allow licensees to use the provisions of ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' subject to NRC-proposed conditions of § 50.55a(b)(2)(xxxvii)(A) through (E), when implementing inservice examinations in accordance with the ASME BPV Code, Section XI requirements.

During the construction of nuclear power plants, it was recognized that the grain structure of cast austenitic stainless steel (CASS) could prevent effective ultrasonic inspections of piping welds where one or both sides of the welds were constructed of CASS. The high strength and toughness of CASS (prior to thermal embrittlement) made it desirable as a building material despite this known inspection issue. This choice of construction materials has rendered many pressure boundary components without a means to reliably inspect them volumetrically. While there is no operational experience of a CASS component failing, as part of the reactor pressure boundary, inservice volumetric inspection of these components is necessary to provide reasonable assurance of their structural integrity.

The current regulatory requirements for the examination of CASS, provided in § 50.55a, do not provide sufficient guidance to assure that the CASS components are being inspected adequately. To illustrate that ASME Code does not provide adequate guidance, ASME Code, Section XI, Appendix III, Supplement 1 states ''Cast materials may preclude meaningful examinations because of geometry and attenuation variables.'' For this reason, over the past several decades, licensees have been unable to perform effective inspections of welds joining CASS components. To allow for continued operation of their plants, licensees submitted hundreds of requests for relief from the ASME Code requirements for inservice inspection of CASS components to the NRC, resulting in a significant regulatory burden. Based on the improvements in ultrasonic inspection technology and techniques for CASS components, the ASME approved BPV Code Case N–824 (N–824) on October 16, 2012, which describes how to develop a procedure capable of meaningfully inspecting welds in CASS components.

The NRC commissioned a research program to determine the effectiveness of the new technologies for inspections of CASS components in an effort to resolve some of the known inspection issues. The result of this work is published in NUREG/CR–6933, ''Assessment of Crack Detection in Heavy-Walled Cast Stainless Steel Piping Welds Using Advanced Low-Frequency Ultrasonic Methods'', March 2007, and NUREG/CR–7122, ''An Evaluation of Ultrasonic Phased Array Testing for Cast Austenitic Stainless Steel Pressurizer Surge Line Piping Welds,'' March 2012. These NUREG/CR reports show that CASS materials less than 1.6 inches thick can be reliably inspected for flaws 10 percent through-wall or deeper if encoded phased-array examinations are performed using low ultrasonic frequencies and a sufficient number of inspection angles. Additionally, for thicker welds, flaws greater than 30 percent through-wall in depth can be detected using low frequency encoded phased-array ultrasonic inspections.

The NRC, using NUREG/CR–6933 and NUREG/CR–7122, has determined that inspections of CASS materials are very challenging, and sufficient technical basis exists to condition the code case to bring the code case into agreement with the NUREG/CR reports. The NUREG/CR reports also show that CASS materials produce high levels of coherent noise. The noise signals can be confusing and mask flaw indications. Use of encoded inspection data allows the inspector to mitigate this problem through the ability to electronically manipulate the data, which allows for discrimination between coherent noise and flaw indications. The NRC finds that encoding CASS inspection data provides significant detection benefits. The NRC proposes to add a condition in § 50.55a(b)(2)(xxxvii)(A) to require the use of encoded data when utilizing N–824 for the examination of CASS components. The use of dual element phased-array search units showed the most promise in obtaining meaningful responses from flaws. The NRC proposes to add a condition in § 50.55a(b)(2)(xxxvii)(B) to require the use of dual, transmit-receive, refracted longitudinal wave, multi-element phased array search units when utilizing N–824 for the examination of CASS components. The optimum inspection frequencies for examining CASS components of various thicknesses as described in NUREG/CR–6933 and NUREG/CR–7122 are reflected in proposed conditions § 50.55a(b)(2)(xxxvii)(C) and (D). The NRC proposes to add a condition in § 50.55a(b)(2)(xxxvii)(C) to require that ultrasonic examinations performed to implement ASME BPV Code Case N–824 on piping less than or equal to 1.6 inches thick shall use a phased array search unit with a center frequency of 500 kHz to 1 MHz. The NRC proposes to add a condition in § 50.55a(b)(2)(xxxvii)(D) to require that ultrasonic examinations performed to implement ASME BPV Code Case N–824 on piping greater than 1.6 inches thick shall use a phased array search unit with a center frequency of 500 kHz. As NUREG/CR–6933 shows that the grain structure of CASS can reduce the effectiveness of some inspection angles, the NRC finds sufficient technical basis to condition the code case for the use of phased-array ultrasound using angles from 30 to 70 degrees with a maximum increment of 5 degrees. The NRC proposes to add a condition in § 50.55a(b)(2)(xxxvii)(E) to require that ultrasonic examinations performed to implement ASME BPV Code Case N–824 shall use a phased array search unit which produces angles from 30 to 70 degrees with a maximum increment of 5 degrees.

Obtaining effective examination results of CASS components requires using lower frequencies and larger transducers than are typically used for ultrasonic inspections of piping welds and would require licensees to modify their inspection procedures. The NRC recognizes that requiring the use of spatial encoding will limit the full implementation of ASME BPV Code Case N–824, as spatial encoding is not practical for many weld configurations.

The recent advances in inspection technology are driving renewed work at ASME Code meetings to produce Section XI, Appendix VIII, Supplement 9 to resolve the CASS inspection issue, but it will be years before these code updates will be published, as well as additional time to qualify and approve procedures for use in the field. Until then, licensees would still use the requirements of ASME Code Section XI, Appendix III, Supplement 1 which states that inspection of CASS materials meeting the ASME Code requirements may not be meaningful. Consequently, less effective examinations would continue to be used in the field, and more relief requests would be generated between now and the implementation of Supplement 9.

At this time, the use of ASME BPV Code Case N–824, as conditioned, is the most effective known method for adequately examining welds with one or more CASS components. With the use of ASME BPV Code Case N–824, as conditioned, licensees will be able to take full credit for completion of the § 50.55a required inservice volumetric inspection of welds involving CASS components. The implementation of ASME BPV Code Case N–824, as conditioned, will have the dual effect of improving the rigor of required volumetric inspections and reducing the number of uninspectable Class 1 and Class 2 pressure retaining welds.

The NRC concludes that incorporation of ASME BPV Code Case N–824, as conditioned by § 50.55a(b)(2)(xxxvii)(A) through (E), will significantly improve the flaw detection capability of ultrasonic inspection of CASS components until Supplement 9 is implemented, thereby providing reasonable assurance of leak tightness and structural integrity. Additionally, it will reduce the regulatory burden on licensees and allow licensees to submit fewer relief requests for welds in CASS materials.

ASME OM Code Case OMN–20

10 CFR 50.55a(b)(3)(x) OM Condition: ASME OM Code Case OMN–20

The NRC proposes to add new paragraph § 50.55a(b)(3)(x) to allow the use of ASME OM Code Case OMN–20, ''Inservice Test Frequency,'' which provides inservice test frequencies for pumps and valves which a licensee may voluntarily use in place of the frequencies specified in the 2012 Edition of the ASME OM Code. Paragraph § 50.55a(a)(1)(iii)(E) would be added to incorporate ASME OM Code Case OMN–20 by reference into § 50.55a. Surveillance Requirement (SR) 3.0.3 from Technical Specification (TS) 5.5.6, ''Inservice Testing Program,'' allows licensees to apply a delay period before declaring the SR for TS equipment ''not met'' when the licensee inadvertently exceeds or misses the time limit for performing TS surveillance. Licensees have been applying SR 3.0.3 to inservice tests. The NRC has determined that licensees cannot use TS 5.5.6 to apply SR 3.0.3 to inservice tests under § 50.55a(f) that are not associated with a TS surveillance. To invoke SR 3.0.3, the licensee shall first discover that a TS surveillance was not performed at its specified frequency. Therefore, the delay period that SR 3.0.3 provides does not apply to non-TS support components tested under § 50.55a(f). The ASME OM Code does not provide for any inservice test frequency reductions or extensions. In order to provide inservice test frequency reductions or extensions that can no longer be provided by SR 3.0.3 from TS 5.5.6, the ASME has developed OM Code Case OMN–20. The NRC has reviewed OM Code Case OMN–20 and has found it acceptable for use. The NRC intends to include OM Code Case OMN–20 in the next revision of RG 1.192, at which time a conforming change will be made to delete both this paragraph and § 50.55a(a)(1)(iii)(E).

IV. Section-by-Section Analysis

The NRC proposes to remove the revision number of the three RGs currently approved by the Office of the Federal Register for incorporation by reference throughout the substantive provisions of § 50.55a. The revision numbers for the RGs approved for incorporation by reference would be retained in paragraph (a) of § 50.55a, where the RGs are listed by full title, including revision number. That paragraph identifies the specific materials which the Office of the Federal Register has approved for incorporation by reference, as required by Office of the Federal Register requirements in 1 CFR 51.9. No substantive change is intended by the NRC by this proposed amendment. Readers would need to refer to paragraph (a) of § 50.55a to determine the specific revision of the relevant RG which is approved for incorporation by reference by Office of the Federal Register.

10 CFR 50.55a(a) Documents Approved for Incorporation by Reference

The NRC proposes to revise the incorporation by reference language to update the contact information for the NRC Technical Library.

10 CFR 50.55a(a)(1)(i) ASME Boiler and Pressure Vessel Code, Section III

The NRC proposes to revise § 50.55a(a)(1)(i) to clarify that Section III Nonmandatory Appendices are not incorporated by reference. This language was originally added in a final rule published on June 21, 2011 (76 FR 36232); however, it was omitted from the final rule published on November 5, 2014 (79 FR 65776). The NRC is correcting the omission by inserting ''(excluding Nonmandatory Appendices)'' in 10 CFR 50.55a(a)(1)(i).

10 CFR 50.55a(a)(1)(i)(E) ''Rules for Construction of Nuclear Facility Components—Division 1''

The NRC proposes to revise § 50.55a(a)(1)(i)(E) to add ASME BPV Code, Section III 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition.

10 CFR 50.55a(a)(1)(ii) ASME Boiler and Pressure Vessel Code, Section XI

The NRC proposes to revise § 50.55a(a)(1)(ii) to include a minor editorial change and to clarify that Nonmandatory Appendix U is not incorporated by reference.

10 CFR 50.55a(a)(1)(ii)(C) ''Rules for Inservice Inspection of Nuclear Power Plant Components—Division 1''

The NRC proposes to revise § 50.55a(a)(1)(ii)(C) to add ASME BPV Code, Section XI 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition.

10 CFR 50.55a(a)(1)(iii)(B) ASME BPV Code Case N–729–4

The NRC proposes to revise § 50.55a(a)(1)(iii)(B) to add the title ''ASME BPV Code Case N–729–4,'' and include information for the standard that is being incorporated by reference.

10 CFR 50.55a(a)(1)(iii)(C) ASME BPV Code Case N–770–2

The NRC proposes to revise § 50.55a(a)(1)(iii)(C) to add the title ''ASME BPV Code Case N–770–2,'' and include information for the standard that is being incorporated by reference.

10 CFR 50.55a(a)(1)(iii)(D) ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(a)(1)(iii)(D) to add the title ''ASME BPV Code Case N–824,'' and include information for the standard that is being incorporated by reference.

10 CFR 50.55a(a)(1)(iii)(E) ASME OM Code Case OMN–20

The NRC proposes to add § 50.55a(a)(1)(iii)(E) to add the title ''ASME OM Code Case OMN–20,'' and include information for the standard that is being incorporated by reference.

10 CFR 50.55a(a)(1)(iv) ASME Operation and Maintenance Code

The NRC proposes to revise § 50.55a(a)(1)(iv) to correct the title of the OM Code.

10 CFR 50.55a(a)(1)(iv)(B) ''Operation and Maintenance of Nuclear Power Plants, Division 1: Section IST Rules for Inservice Testing of Light-Water Reactor Power Plants''

The NRC proposes to revise § 50.55a(a)(1)(iv)(B) to add ASME OM Code 2009 Edition and 2011 Addenda.

10 CFR 50.55a(a)(1)(iv)(C) ''Operation and Maintenance of Nuclear Power Plants, Division 1: OM Code: Section IST''

The NRC proposes to add § 50.55a(a)(1)(iv)(C) to add ASME OM Code 2012 Edition.

10 CFR 50.55a(a)(1)(v) ASME Quality Assurance Requirements

The NRC proposes to add § 50.55a(a)(1)(v) to add the title ''ASME Quality Assurance Requirements'' for ASME NQA–1 Code as part of NRC titling convention and include information regarding NQA–1 standards.

10 CFR 50.55a(b) Use and Conditions on the Use of Standards

The NRC proposes to revise § 50.55a(b) to correct the title of the OM Code.

10 CFR 50.55a(b)(1) Conditions on ASME BPV Code Section III

The NRC proposes to revise § 50.55a(b)(1) to reflect the latest edition incorporated by reference, the 2013 Edition.

10 CFR 50.55a(b)(1)(ii) Section III Condition: Weld Leg Dimensions

The NRC proposes to revise § 50.55a(b)(1)(ii) to clarify rule language and add Table 1, which clarifies prohibited Section III provisions in tabular form for welds with leg size less than 1.09 t_n.

10 CFR 50.55a(b)(1)(iv) Section III Condition: Quality Assurance

The NRC proposes to revise § 50.55a(b)(1)(iv) to clarify that it allows, but does not require, applicants and licensees to use the 2008 Edition through the 2009–1a Addenda of NQA–1 when applying the 2010 Edition and later editions of the ASME BPV Code, Section III, up to the 2011 Addenda.

Applicants and licensees are required to meet appendix B of 10 CFR part 50, and NQA–1 is one way of meeting portions of appendix B. An applicant or licensee may select any version of NQA–1 that has been approved for use in § 50.55a, but they must also use the administrative, quality, and technical provisions contained in the version of NCA–4000 referencing that Edition or Addenda of NQA–1 selected by the applicant or licensee.

NQA–1 provides a method for establishing and implementing a QA program for the design and construction of nuclear power plants and fuel reprocessing plants; however, NQA–1, as modified and supplemented by NCA–4000, does not meet all of the requirements of appendix B to 10 CFR part 50. To meet the requirements of appendix B, when using NQA–1 during the design and construction phase, applicants and licensees must address in their quality program description those areas where NQA–1 is insufficient to meet appendix B. Regulatory Guide 1.28, ''Quality Assurance Criteria (Design and Construction),'' provides additional guidance and regulatory positions on how to meet appendix B when using NQA–1.

Section 50.55a(b)(1)(iv) clarifies that applicants and licensees are required to meet appendix B to 10 CFR part 50 and that the commitments contained in their QA program descriptions that are more stringent than those contained in NQA–1 or are not addressed in NQA–1 apply to Section III activities.

10 CFR 50.55a(b)(1)(vii) Section III Condition: Capacity Certification and Demonstration of Function of Incompressible-Fluid Pressure-Relief Valves

The NRC proposes to revise § 50.55a(b)(1)(vii) to reflect the latest edition incorporated by reference, the 2013 Edition.

10 CFR 50.55a(b)(1)(viii) Section III Condition: Use of ASME Certification Marks

The NRC proposes to add § 50.55a(b)(1)(viii) to allow licensees to use either the ASME BPV Code Symbol Stamp or ASME Certification Mark with the appropriate certification designator and class designator as specified in the 2013 Edition through the latest edition and addenda incorporated by reference in 10 CFR 50.55a.

10 CFR 50.55a(b)(2) Conditions on ASME BPV Code, Section XI

The NRC proposes to revise § 50.55a(b)(2) to reflect the latest edition incorporated by reference, the 2013 Edition, and to clarify that Nonmandatory Appendix U is not incorporated by reference.

10 CFR 50.55a(b)(2)(vi) Section XI Condition: Effective Edition and Addenda of Subsection IWE and Subsection IWL

The NRC proposes to revise § 50.55a(b)(2)(vi) to clarify that the provision applies only to the class of licensees of operating reactors that were required by previous versions of § 50.55a to develop and implement a containment inservice inspection program in accordance with Subsection IWE and Subsection IWL, and complete an expedited examination of containment during the 5-year period from September 9, 1996 to September 9, 2001.

10 CFR 50.55a(b)(2)(viii) Section XI Condition: Concrete Containment Examinations

The NRC proposes to revise § 50.55a(b)(2)(viii) by removing the condition for using the 2009 Addenda up to and including the 2013 Edition of Subsection IWL requiring compliance with § 50.55a(b)(2)(viii)(E).

10 CFR 50.55a(b)(2)(viii)(H) Concrete Containment Examinations: Eighth Provision

The NRC proposes to add § 50.55a(b)(2)(viii)(H) to require licensees to provide the applicable information specified in paragraphs (b)(2)(viii)(E)(*1*), (b)(2)(viii)(E)(*2*), and (b)(2)(viii)(E)(*3*) of this section in the ISI Summary Report required by IWA–6000 for each inaccessible concrete surface area evaluated under the new code provision IWL–2512 of the 2009 Addenda up to and including the 2013 Edition.

10 CFR 50.55a(b)(2)(viii)(I) Concrete Containment Examinations: Ninth Provision

The NRC proposes to add § 50.55a(b)(2)(viii)(I) containing a new condition requiring the technical evaluation required by IWL–2512(b) of the 2009 Addenda up to and including the 2013 Edition of inaccessible below-grade concrete surfaces exposed to foundation soil, backfill, or groundwater be performed at periodic intervals not to exceed 5 years. In addition, the licensee must examine representative samples of the exposed portions of the below-grade concrete, when such below-grade concrete is excavated for any reason. The proposed condition would apply only to holders of renewed licenses under 10 CFR part 54 during the period of extended operation (*i.e.,* beyond the expiration date of the original 40-year license) of a renewed license when using IWL–2512(b) of the 2007 Edition with 2009 Addenda through the 2013 Edition.

10 CFR 50.55a(b)(2)(ix) Section XI Condition: Metal Containment Examinations

The NRC proposes to revise § 50.55a(b)(2)(ix) to continue to apply the existing conditions in § 50.55a(b)(2)(ix)(A)(*2*), § 50.55a(b)(2)(ix)(B) and § 50.55a(b)(2)(ix)(J) with respect to the metal containment examination requirements in Subsection IWE to the 2009 Addenda up to and including the 2013 Edition and to make minor editorial corrections.

10 CFR 50.55a(b)(2)(ix)(D) Metal Containment Examinations: Fourth Provision

The NRC proposes to revise the rule text in § 50.55a(b)(2)(ix)(D) to improve clarity. Paragraphs § 50.55a(b)(2)(ix)(D) and § 50.55a(b)(2)(ix)(D)(1) are combined. The information required to be included in the ISI Summary report is now all on the same paragraph level. No substantive change to the requirements is intended by this revision.

10 CFR 50.55a(b)(2)(x) Section XI Condition: Quality Assurance

The NRC proposes to revise § 50.55a(b)(2)(x) to clarify that it allows, but does not require, licensees to use the 1994 or the 2008 Edition through the 2009–1a Addenda of NQA–1 when applying the 2009 Addenda and later editions and addenda of the ASME BPV Code, Section XI, up to the 2013 Edition. Licensees are required to meet appendix B of 10 CFR part 50, and NQA–1 is one way of meeting portions of appendix B. A licensee may select any version of NQA–1 that has been approved for use in § 50.55a.

NQA–1 provides a method for establishing and implementing a QA program for the design and construction of nuclear power plants and fuel reprocessing plants; however, NQA–1 does not meet all of the requirements of appendix B to 10 CFR part 50. To meet the requirements of appendix B, when using NQA–1 during inservice inspection phase, licensees must address in their quality program description those areas where NQA–1 is insufficient to meet appendix B. Additional guidance and regulatory positions on how to meet appendix B when using NQA–1 is provided in RG 1.28, ''Quality Assurance Criteria (Design and Construction).''

Section 50.55a(b)(2)(x) clarifies that licensees are required to meet appendix B to 10 CFR part 50 and that the commitments contained in their QA program descriptions that are more stringent than those contained in NQA–1 or are not addressed in NQA–1 apply to Section XI activities.

10 CFR 50.55a(b)(2)(xviii)(D) NDE Personnel Certification: Fourth Provision

The NRC proposes to add § 50.55a(b)(2)(xviii)(D) to provide a new condition prohibiting the use of Appendix VII and subarticle VIII–2200 of the 2011 Addenda and 2013 Edition of Section XI of the ASME BPV Code. Licensees would be required to implement Appendix VII and subarticle VIII–2200 of the 2010 Edition of Section XI.

10 CFR 50.55a(b)(2)(xxi)(A) Table IWB–2500–1 Examination Requirements: First Provision

The NRC proposes to revise § 50.55a(b)(2)(xxi)(A) to modify the standard for visual magnification resolution sensitivity and contrast for visual examinations performed on Examination Category B–D components instead of ultrasonic examinations. A visual examination with magnification that has a resolution sensitivity to resolve 0.044 inch (1.1 mm) lower case characters without an ascender or descender (*e.g.,* a, e, n, v), utilizing the allowable flaw length criteria in Table IWB–3512–1, 1997 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, with a limiting assumption on the flaw aspect ratio (*i.e.,* a/l = 0.5), may be performed instead of an ultrasonic examination. This revision removes a requirement that was in addition to ASME BPV Code that required 1-mil wires to be used in licensees' Sensitivity, Resolution and Contrast Standard targets.

10 CFR 50.55a(b)(2)(xxx) Section XI Condition: Steam Generator Preservice Examinations

The NRC proposes to add § 50.55a(b)(2)(xxx) to provide a new condition requiring that instead of the preservice inspection requirements of Section XI, IWB–2200(c), a full length examination of 100 percent of the tubing in each newly installed steam generator shall be performed prior to plant startup. These inspections shall be performed with the objective of finding the types of flaws that may potentially be present in the tubes and that may potentially occur during operation.

10 CFR 50.55a(b)(2)(xxxi) Section XI Condition: Mechanical Clamping Devices

The NRC proposes to add § 50.55a(b)(2)(xxxi) to provide a new condition prohibiting the use of mechanical clamping devices in accordance with IWA–4131.1(c) in the 2010 Edition and IWA–4131.1(d) in the 2011 Addenda through 2013 Edition on small item Class 1 piping and portions of a piping system that forms the containment boundary.

10 CFR 50.55a(b)(2)(xxxii) Section XI Condition: Summary Report Submittal

The NRC proposes to add § 50.55a(b)(2)(xxxii) to provide a new condition requiring licensees using the 2010 Edition or later editions and addenda of Section XI to follow the requirements of IWA–6240 of the 2009 addenda of Section XI for the submittal of Preservice and Inservice Summary Reports.

10 CFR 50.55a(b)(2)(xxxiii) Section XI Condition: Risk-Informed Allowable Pressure

The NRC proposes to add § 50.55a(b)(2)(xxxiii) to provide a new condition to prohibit the use of Appendix G Paragraph G–2216 in the 2011 Addenda and later editions and addenda of the ASME BPV Code, Section XI.

10 CFR 50.55a(b)(2)(xxxiv) Section XI Condition: Disposition of Flaws in Class 3 Components

The NRC proposes to add § 50.55a(b)(2)(xxxiv) to provide a new condition to require that when using the 2013 Edition of the ASME BPV Code, Section XI, the licensee shall use the acceptance standards of IWD–3510 for the disposition of flaws in Category D–A components (*i.e.,* welded attachments for vessels, piping, pumps, and valves).

10 CFR 50.55a(b)(2)(xxxv) Section XI Condition: Use of RT_{T0} in the K_{Ia} and K_{Ic} Equations

The NRC proposes to add § 50.55a(b)(2)(xxxv) to provide a new condition to specify that when licensees use ASME BPV Code, Section XI, 2013 Edition Appendix A paragraph A–4200, if T_0 is available, then RT_{T0} may be used in place of RT_{NDT} for applications using the K_{Ic} equation and the associated K_{Ic} curve, but not for applications using the K_{Ia} equation and the associated K_{Ia} curve.

10 CFR 50.55a(b)(2)(xxxvi) Section XI Condition: Fracture Toughness of Irradiated Materials

The NRC proposes to add § 50.55a(b)(2)(xxxvi) to provide a new condition requiring licensees using ASME BPV Code, Section XI, 2013 Edition, Appendix A, paragraph A–4400, to obtain NRC approval before using irradiated T_0 and the associated RT_{T0} in establishing fracture toughness of irradiated materials.

10 CFR 50.55a(b)(2)(xxxvii) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii) with subparagraphs (A) through (E) to provide a new provision that allows licensees to implement ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' as conditioned by subparagraphs (A) through (E).

10 CFR 50.55a(b)(2)(xxxvii)(A) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii)(A) to add a new condition that requires ultrasonic examinations performed to implement ASME BPV Code Case N–824 to be spatially encoded.

10 CFR 50.55a(b)(2)(xxxvii)(B) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii)(B) to add a new condition that requires that ultrasonic examinations performed to implement ASME BPV Code Case N–824 shall use dual, transmit-receive, refracted longitudinal wave, multi-element phased array search units instead of the requirements of Paragraph 1(c)(1)(–a) of N–824.

10 CFR 50.55a(b)(2)(xxxvii)(C) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii)(C) to add a new condition that requires that ultrasonic examinations performed to implement ASME BPV Code Case N–824 on piping less than or equal to 1.6 inches thick shall use a phased array search unit with a center frequency of 500 kHz to 1 MHz instead of the requirements of Paragraph 1(c)(1)(–c)(–1).

10 CFR 50.55a(b)(2)(xxxvii)(D) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii)(D) to add a new condition that requires that ultrasonic examinations performed to implement ASME BPV Code Case N–824 on piping greater than 1.6 inches thick shall use a phased array search unit with a center frequency of 500 kHz instead of the requirements of Paragraph 1(c)(1)(–c)(–2).

10 CFR 50.55a(b)(2)(xxxvii)(E) Section XI Condition: ASME BPV Code Case N–824

The NRC proposes to add § 50.55a(b)(2)(xxxvii)(E) to add a new condition that requires that ultrasonic examinations performed to implement ASME BPV Code Case N–824 shall use a phased array search unit which produces angles from 30 to 70 degrees with a maximum increment of 5 degrees instead of the requirements of Paragraph 1(c)(1)(–d).

10 CFR 50.55a(b)(3) Conditions on ASME OM Code

The NRC proposes to revise § 50.55a(b)(3) to require that the 2012 Edition of the ASME OM Code be used during the initial 120-month inservice test interval under § 50.55a(f)(4)(i) and during mandatory 120-month IST program updates under § 50.55a(f)(4)(ii). The proposed revision would also allow users to voluntarily update their IST programs to the 2009 Edition, 2011 Addenda, or 2012 Edition of the ASME OM Code (with the exceptions and conditions specified in this notice) under § 50.55a(f)(4)(iv).

10 CFR 50.55a(b)(3)(i) OM Condition: Quality Assurance

The NRC proposes to revise § 50.55a(b)(3)(i) to allow licensees to use the 1983 Edition through the 1994 Edition, 2008 Edition, and 2009–1a Addenda of NQA–1 when using the 1995 Edition through the 2012 Edition of the ASME OM Code. Licensees are required to meet appendix B to 10 CFR part 50, and NQA–1 is one way of meeting portions of appendix B.

NQA–1 provides a method for establishing and implementing a QA program for the design and construction of nuclear power plants and fuel reprocessing plants; however, NQA–1 does not meet all of the requirements of appendix B to 10 CFR part 50. To meet the requirements of appendix B, licensees must address in their quality program description those areas where NQA–1 is insufficient to meet appendix B. Regulatory Guide 1.28, ''Quality Assurance Criteria (Design and Construction),'' provides additional guidance on how to meet appendix B when using NQA–1.

Paragraph 50.55a(b)(3)(i) clarifies that licensees are required to meet appendix B to 10 CFR part 50 and that the commitments contained in their QA program descriptions that are more stringent than those contained in NQA–1 or are not addressed in NQA–1 apply to OM Code activities.

10 CFR 50.55a(b)(3)(ii) OM Condition: Motor-Operated Valve (MOV) Testing

The NRC proposes to revise § 50.55a(b)(3)(ii) to reflect Appendix III, ''Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants,'' in the ASME OM Code, 2009 Edition, 2011 Addenda, and 2012 Edition.

10 CFR 50.55a(b)(3)(ii)(A) MOV Diagnostic Test Interval

The NRC proposes to add § 50.55a(b)(3)(ii)(A) to require that licensees evaluate the adequacy of the diagnostic test interval for each MOV and adjust the interval as necessary, but not later than 5 years or three refueling outages (whichever is longer) from initial implementation of Appendix III of the ASME OM Code.

10 CFR 50.55a(b)(3)(ii)(B) MOV Testing Impact on Risk

The NRC proposes to add § 50.55a(b)(3)(ii)(B) to require that licensees ensure that the potential increase in core damage frequency and large early release frequency associated with the extension is acceptably small when extending exercise test intervals for high risk MOVs beyond a quarterly frequency.

10 CFR 50.55a(b)(3)(ii)(C) MOV Risk Categorization

The NRC proposes to add § 50.55a(b)(3)(ii)(C) to require, when applying Appendix III to the ASME OM Code, that licensees categorize MOVs according to their safety significance using the methodology described in ASME OM Code Case OMN–3 subject to the conditions discussed in RG 1.192, or using an MOV risk ranking methodology accepted by the NRC on a plant-specific or industry-wide basis in accordance with the conditions in the applicable safety evaluation.

10 CFR 50.55a(b)(3)(ii)(D) MOV Stroke Time

The NRC proposes to add § 50.55a(b)(3)(ii)(D) to require, when applying Paragraph III–3600, ''MOV Exercising Requirements,'' of Appendix III to the OM Code, licensees shall verify that the stroke time of the MOV satisfies the assumptions in the plant safety analyses.

10 CFR 50.55a(b)(3)(iii) OM Condition: New Reactors

The NRC proposes to add § 50.55a(b)(3)(iii) to specify that, in addition to complying with the provisions in the OM Code as required with the conditions specified in § 50.55a(b)(3), holders of operating licenses for nuclear power reactors that received construction permits under this part on or after the date 12 months after the effective date of this rulemaking and holders of COLs issued under 10 CFR part 52, whose initial fuel loading occurs on or after the date 12 months after the effective date of this rulemaking, shall also comply with specified conditions, as applicable.

10 CFR 50.55a(b)(3)(iii)(A) Power-Operated Valves

The NRC proposes to add § 50.55a(b)(3)(iii)(A) to require that licensees subject to § 50.55a(b)(3)(iii) develop a program to periodically verify the capability of power-operated valves (POVs) to perform their design-basis safety functions.

10 CFR 50.55a(b)(3)(iii)(B) Check Valves

The NRC proposes to add § 50.55a(b)(3)(iii)(B) to require that licensees subject to § 50.55a(b)(3)(iii) perform bi-directional testing of check valves within the IST program where practicable.

10 CFR 50.55a(b)(3)(iii)(C) Flow-Induced Vibration

The NRC proposes to add § 50.55a(b)(3)(iii)(C) to require that licensees subject to § 50.55a(b)(3)(iii) monitor flow-induced vibration (FIV) from hydrodynamic loads and acoustic resonance during preservice testing and inservice testing to identify potential adverse flow effects that might impact components within the scope of the IST program.

10 CFR 50.55a(b)(3)(iii)(D) High Risk Non-Safety Systems

The NRC proposes to add § 50.55a(b)(3)(iii)(D) to require that licensees subject to § 50.55a(b)(3)(iii) establish a program to assess the operational readiness of pumps, valves, and dynamic restraints within the scope of the Regulatory Treatment of Non-Safety Systems (RTNSS) for applicable reactor designs. The proposed rule language refers to such components using the term, ''high risk non-safety systems.''

10 CFR 50.55a(b)(3)(iv) OM Condition: Check Valves (Appendix II)

The NRC proposes to revise § 50.55a(b)(3)(iv) to specify that Appendix II in the 2003 Addenda through the 2012 Edition of the OM Code is acceptable for use without conditions with the clarifications that (1) the maximum test interval allowed by Appendix II for individual check valves in a group of two valves or more must be supported by periodic testing of a sample of check valves in the group during the allowed interval and (2) the periodic testing plan must be designed to test each valve of a group at approximate equal intervals not to exceed the maximum requirement interval. The conditions currently specified for the use of Appendix II, 1995 Edition with the 1996 and 1997 Addenda, and 1998 Edition through the 2002 Addenda, of the OM Code remain the same in this proposed rule.

10 CFR 50.55a(b)(3)(vii) OM Condition: Subsection ISTB

The NRC proposes to add § 50.55a(b)(3)(vii) to prohibit the use of Subsection ISTB in the 2011 Addenda to the ASME OM Code.

10 CFR 50.55a(b)(3)(viii) OM Condition: Subsection ISTE

The NRC proposes to add § 50.55a(b)(3)(viii) to specify that licensees who wish to implement Subsection ISTE, ''Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants,'' of the ASME OM Code, 2009 Edition, 2011 Addenda, and 2012 Edition, must first request and obtain NRC approval in accordance with § 50.55a(z) to apply Subsection ISTE on a plant-specific basis as a risk-informed alternative to the applicable IST requirements in the ASME OM Code.

10 CFR 50.55a(b)(3)(ix) OM Condition: Subsection ISTF

The NRC proposes to add § 50.55a(b)(3)(ix) to specify that licensees applying Subsection ISTF, ''Inservice Testing of Pumps in Light-Water Reactor Nuclear Power Plants—Post-2000 Plants,'' in the 2012 Edition of the OM Code shall satisfy the requirements of Mandatory Appendix V, ''Pump Periodic Verification Test Program,'' of the OM Code, 2012 Edition. The proposed paragraph will also state that Subsection ISTF, 2011 Addenda, is not acceptable for use.

10 CFR 50.55a(b)(3)(x) OM Condition: ASME OM Code Case OMN–20

The NRC proposes to add § 50.55a(b)(3)(x) to allow licensees to implement ASME OM Code Case OMN–20, ''Inservice Test Frequency,'' in the ASME OM Code, 2012 Edition.

10 CFR 50.55a(b)(3)(xi) OM Condition: Valve Position Indication

The NRC proposes to add § 50.55a(b)(3)(xi) to require that licensees supplement the ASME OM Code provisions in Subsection ISTC–3700, ''Position Verification Testing,'' as necessary to verify that valve operation is accurately indicated. The ASME OM Code, Subsection ISTC–3700 requires valves with remote position indicators shall be observed locally at least once every 2 years to verify that valve operation is accurately indicated.

10 CFR 50.55a(f): Inservice Testing Requirements

The NRC proposes to revise § 50.55a(f) to clarify that the ASME OM Code includes provisions for preservice testing of components as part of its overall provisions for IST programs.

10 CFR 50.55a(f)(3)(iii)(A) Class 1 Pumps and Valves: First Provision

The NRC proposes to revise § 50.55a(f)(3)(iii)(A) to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(3)(iii)(B) Class 1 Pumps and Valves: Second Provision

The NRC proposes to revise § 50.55a(f)(3)(iii)(B) to ensure that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(3)(iv)(A) Class 2 and 3 Pumps and Valves: First Provision

The NRC proposes to revise § 50.55a(f)(3)(iv)(A) to ensure that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(A) for Class 1 pumps and valves. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(3)(iv)(B) Class 2 and 3 Pumps and Valves: Second Provision

The NRC proposes to revise § 50.55a(f)(3)(iv)(B) to ensure that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(B) for Class 1 pumps and valves. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME Code and in SRP Section 3.9.6.

10 CFR 50.55a(f)(4) Inservice Testing Standards Requirement for Operating Plants

The NRC proposes to revise § 50.55a(f)(4) to ensure that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME Code and in SRP Section 3.9.6.

10 CFR 50.55a(g) Inservice and Preservice Inspection Requirements

The NRC proposes to add new paragraphs (g)(2)(i), (g)(2)(ii), and (g)(2)(iii) and to revise paragraphs (g), (g)(2), (g)(3), (g)(3)(i), (g)(3)(ii), and (g)(3)(v) to distinguish the requirements for accessibility and preservice examination from those for inservice inspection in § 50.55a(g). No substantive change to the requirements is intended by these revisions.

10 CFR 50.55a(g)(6)(ii)(D)(1) Implementation

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*1*) to require licensees to implement an augmented inservice inspection program for the examination of the RPV upper head penetrations meeting ASME BPV Code Case N–729–4 instead of the previously approved requirements to use ASME BPV Code Case N–729–1, as conditioned by the NRC.

10 CFR 50.55a(g)(6)(ii)(D)(2) Through (5) of the Current Regulation

The NRC proposes to remove the conditions in existing § 50.55a(g)(6)(ii)(D)(*2*) through (*5*) of the current regulation, inasmuch as these conditions have been included in or reflected in other Code requirements. In their place, the NRC proposes to adopt new conditions in § 50.55a(g)(6)(ii)(D)(*2*) through (*4*).

10 CFR 50.55a(g)(6)(ii)(D)(2) Appendix I Use

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*2*) to require NRC approval prior to implementing Appendix I of ASME BPV Code Case N–729–4. This requirement is currently located in § 50.55a(g)(6)(ii)(D)(*6*) for implementation of N–729–1.

10 CFR 50.55a(g)(6)(ii)(D)(3) Bare Metal Visual Frequency

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*3*) to add a new condition which requires cold head plants (EDY<8) without PWSCC flaws to perform a bare metal visual examination (VE) each outage a volumetric exam is not performed and allows these plants to extend the bare metal visual inspection frequency from once each refueling outage, as stated in Table 1 of N–729–4, to once every 5 years only if the licensee performed a wetted surface examination of all of the partial penetration welds during the previous volumetric examination. In addition, this new condition clarifies that a bare metal visual examination is not required during refueling outages when a volumetric or surface examination is performed of the partial penetration welds. The condition that is in the current § 50.55a(g)(6)(ii)(D)(*3*) was incorporated into N–729–4 by the ASME Code committees.

10 CFR 50.55a(g)(6)(ii)(D)(4) Surface Exam Acceptance Criteria

The NRC proposes to revise § 50.55a(g)(6)(ii)(D)(*4*) to add a new condition which clarifies that rounded indications found by surface examinations of the partial-penetration or associated fillet welds in accordance with N–729–4 must meet the acceptance criteria for surface examinations of paragraph NB–5352 of ASME Section III of the current edition and addenda for the licensee's ongoing 10-year inservice inspection interval. The condition that is in the current § 50.55a(g)(6)(ii)(D)(*4*) was incorporated into N–729–4 by the ASME Code committees.

10 CFR 50.55a(g)(6)(ii)(F)(1) Implementation

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*1*) to require licensees to implement an augmented inservice inspection program for the examination of ASME Class 1 piping and nozzle butt welds meeting ASME BPV Code Case N–770–2 instead of the previously approved ASME BPV Code Case N–770–1.

Furthermore, the NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*1*) to update the date of applicability for pressurized water reactors, to note the change to implement ASME BPV Code Case N–770–2 instead of N–770–1, and to reflect the number of conditions which must be applied.

10 CFR 50.55a(g)(6)(ii)(F)(2) Categorization

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*2*) to clarify the requirements for licensees to establish the initial categorization of each weld and modify the wording to reflect the ASME BPV Code Case N–770–2 change in the inspection item category for full structural weld overlays. Additionally, the NRC proposes to add a sentence which clarifies the NRC position that paragraph -1100(e) of ASME BPV Code Case N–770–2 shall not be used to exempt welds that rely on Alloy 82/182 for structural integrity from any requirement of § 50.55a(g)(6)(ii)(F).

10 CFR 50.55a(g)(6)(ii)(F)(3) Baseline Examinations

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*3*) to clarify the current requirement in this paragraph to complete baseline examinations. Additionally, this condition clarifies that the examination coverage requirements, for a licensee to count previous inspections as baseline examinations, are the same examination coverage requirements described in paragraphs -2500(a) or -2500(b) of ASME BPV Code Case N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(4) Examination Coverage

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*4*) to clarify that licensees are required to ensure greater than 90 percent volumetric examination coverage is obtained for circumferential flaws, to continue the restriction on the licensee's use of paragraph –2500(c) and to continue the restriction that the use of new paragraph –2500(d) of ASME BPV Code Case N–770–2 is not allowed without prior NRC review and approval in accordance with § 50.55a(z), as it would permit a reduction in volumetric examination coverage for circumferential flaws.

10 CFR 50.55a(g)(6)(ii)(F)(5) Inlay/Onlay Inspection Frequency

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*5*) to add explanatory heading and to make minor editorial corrections.

10 CFR 50.55a(g)(6)(ii)(F)(6) Reporting Requirements

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*6*) to add explanatory heading.

10 CFR 50.55a(g)(6)(ii)(F)(7) Defining "t"

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*7*) to add explanatory heading.

10 CFR 50.55a(g)(6)(ii)(F)(8) Optimized Weld Overlay Examination

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*8*) to continue the current condition located in § 50.55a(g)(6)(ii)(F)(*9*) which requires that the initial examination of optimized weld overlays (*i.e.,* Inspection Item C–2 of ASME BPV Code Case N–770–2) be performed between the third refueling outage and no later than 10 years after application of the overlay and delete the other current examination requirements for optimized weld overlay examination frequency, as these requirements were included in the revision from N–770–1 to N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(9) Deferral

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*9*) to modify the current condition to continue denial of the deferral of the initial inservice examination of uncracked welds mitigated by optimized weld overlays. These welds shall continue to have their initial inservice examinations as prescribed in N–770–1 within 10 years of the application of the optimized weld overlay and not allow deferral of this initial examination. Subsequent inservice examinations may be deferred as allowed by N–770–2. Additionally, the modified condition will delete the current condition on examination requirements for the deferral of welds mitigated by inlay, onlay, stress improvement and optimized weld overlay, as these requirements were, with one exception (*i.e.,* optimized weld overlay), included in the revision from N–770–1 to N–770–2.

10 CFR 50.55a(g)(6)(ii)(F)(10) Examination Technique

The NRC proposes to revise § 50.55a(g)(6)(ii)(F)(*10*) to modify the current condition to allow the previously prohibited alternate examination requirements of Note (b) of Figure 5(a) of ASME BPV Code Case N–770–1 and N–770–2 and the same requirements in Note 14(b) of Table 1 of ASME BPV Code Case N–770–2 for optimized weld overlays only if the full examination requirements of Note 14(a) of Table 1 of ASME BPV Code Case N–770–2 cannot be met.

10 CFR 50.55a(g)(6)(ii)(F)(11) Cast Stainless Steel

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(*11*) to provide a new condition requiring licensees to establish a Section XI Appendix VIII qualification requirement for ultrasonic inspection of and through cast stainless steel to meet the examination requirements of paragraph -2500(a) of

ASME BPV Code Case N–770–2 by January 1, 2020.

10 CFR 50.55a(g)(6)(ii)(F)(12) Stress Improvement Inspection Coverage

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(*12*) to provide a new condition that would allow licenses to implement a stress improvement mitigation technique for items containing cast stainless steel that would meet the requirements of Appendix I of ASME BPV Code Case N–770–2, if the required examination volume can be examined by Appendix VIII procedures to the maximum extent practical including 100 percent of the susceptible material volume.

10 CFR 50.55a(g)(6)(ii)(F)(13) Encoded Ultrasonic Examination

The NRC proposes to add § 50.55a(g)(6)(ii)(F)(*13*) to provide a new condition requiring licensees to perform encoded examinations of essentially 100 percent of the inspection surface area when required to perform volumetric examinations of all non-mitigated and cracked mitigated butt welds in accordance with N–770–2.

V. Generic Aging Lessons Learned Report

Background

In December 2010, the NRC issued ''Generic Aging Lessons Learned (GALL) Report,'' NUREG–1801, Revision 2, for applicants to use in preparing their license renewal applications. The GALL Report provides aging management programs (AMPs) that the NRC staff has concluded are sufficient for aging management in accordance with the license renewal rule, as required in 10 CFR 54.21(a)(3). In addition, ''Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants,'' NUREG–1800, Revision 2 was issued in December 2010 to ensure the quality and uniformity of NRC staff reviews of license renewal applications and to present a well-defined basis on which the NRC staff evaluates the applicant's aging management programs and activities. In April 2011, the NRC also issued ''Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG–1801 and NUREG–1800,'' NUREG–1950, which describes the technical bases for the changes in Revision 2 of the GALL Report and Revision 2 of the SRP for review of license renewal applications.

Revision 2 of the GALL Report, in Sections XI.M1, XI.S1, XI.S2, and XI.S3, describes the evaluation and technical bases for determining the sufficiency of ASME BPV Code Subsections IWB, IWC, IWD, IWE, IWF, and IWL for managing aging during the period of extended operation. In addition, many other aging management programs in the GALL Report rely, in part but to a lesser degree, on the requirements specified in the ASME BPV Code, Section XI. Revision 2 of the GALL Report also states that the 1995 Edition through the 2004 Edition of the ASME BPV Code, Section XI, Subsections IWB, IWC, IWD, IWE, IWF, and IWL, as modified and limited by § 50.55a, were found to be acceptable editions and addenda for complying with the requirements of 10 CFR 54.21(a)(3), unless specifically noted in certain sections of the GALL Report. The GALL Report further states that the future **Federal Register** notices that amend § 50.55a will discuss the acceptability of editions and addenda more recent than the 2004 edition for their applicability to license renewal. In a final rule issued on June 21, 2011 (76 FR 36232), subsequent to Revision 2 of the GALL Report, the NRC also found that the 2004 Edition with the 2005 Addenda through the 2007 Edition with the 2008 Addenda of Section XI of the ASME BPV Code, Subsections IWB, IWC, IWD, IWE, IWF, and IWL, as subject to the conditions in § 50.55a, are acceptable for the AMPs in the GALL Report and the conclusions of the GALL Report remain valid with the augmentations specifically noted in the GALL Report.

Evaluation With Respect to Aging Management

As part of this rulemaking, the NRC evaluated whether those AMPs in Revision 2 of the GALL Report which rely upon Subsections IWB, IWC, IWD, IWE, IWF, and IWL of Section XI in the editions and addenda of the ASME BPV Code incorporated by reference into § 50.55a, continue to be acceptable if the AMP relies upon the versions of these Subsections in the 2007 Edition with the 2009 Addenda through the 2013 Edition. The NRC finds that the 2007 Edition with the 2009 Addenda through the 2013 Edition of Section XI of the ASME BPV Code, Subsections IWB, IWC, IWD, IWE, IWF, and IWL, as subject to the conditions of this rule, are acceptable for the AMPs in the GALL Report and the conclusions of the GALL Report remain valid with the augmentations specifically noted in the GALL Report. Accordingly, an applicant for license renewal may use, in its plant-specific license renewal application, Subsections IWB, IWC, IWD, IWE, IWF, and IWL of Section XI of the 2007 Edition with the 2009 Addenda through the 2013 Edition of the ASME BPV Code, as subject to the conditions in this rule, without additional justification. Similarly, a licensee approved for license renewal that relied on the GALL AMPs may use Subsections IWB, IWC, IWD, IWE, IWF, and IWL of Section XI of the 2007 Edition with the 2009 Addenda through the 2013 Edition of the ASME BPV Code. However, a licensee must assess and follow applicable NRC requirements with regard to changes to its licensing basis.

Some of the AMPs in the GALL Report recommend augmentation of certain Code requirements in order to ensure adequate aging management for license renewal. The technical and regulatory aspects of the AMPs for which augmentations are recommended also apply if the editions or addenda from the 2007 Edition with the 2009 Addenda through the 2013 Edition of Section XI of the ASME BPV Code are used to meet the requirements of 10 CFR 54.21(a)(3). The NRC staff evaluated the changes in the 2007 Edition with the 2009 Addenda through the 2013 Edition of Section XI of the ASME BPV Code to determine if the augmentations described in the GALL Report remain necessary; the NRC staff's evaluation has concluded that the augmentations described in the GALL Report are necessary to ensure adequate aging management. For example, Table IWB–2500–1, in the 2007 Edition with the 2009 Addenda of ASME BPV Code, Section XI, Subsection IWB, requires surface examination of ASME Code Class 1 branch pipe connection welds less than nominal pipe size (NPS) 4 under Examination Category B–J. However, the NRC staff finds that volumetric or opportunistic destructive examination rather than surface examination is necessary to adequately detect and manage the aging effect due to stress corrosion cracking or thermal, mechanical and vibratory loadings in the components for the period of extended operation. Therefore, GALL Report Section XI.M35, ''One-Time Inspection of ASME Code Class 1 Small-Bore Piping,'' includes the augmentation of the requirements in ASME BPV Code, Section XI, Subsection IWB to perform a one-time inspection of a sample of ASME Code Class 1 piping less than NPS 4 and greater than or equal to NPS 1 using volumetric or opportunistic destructive examination. The GALL Report addresses this augmentation to confirm that there is no need to manage age-related degradation through periodic volumetric inspections or that an existing AMP (for example, Water

Chemistry AMP) is effective to manage the aging effect due to stress corrosion cracking or thermal, mechanical and vibratory loadings for the period of extended operation. A license renewal applicant may either augment its AMPs as described in the GALL Report, or propose alternatives for the NRC to review as part of the applicant's plant-specific justification for its AMPs.

VI. Specific Request for Comments

The NRC requests specific comments on the following questions:

NRC Question 1. *NQA–1.* The NRC is considering removing the references to versions of NQA–1 older than the 1994 Edition in § 50.55a(b)(1)(iv), § 50.55a(b)(2)(x), and § 50.55a(b)(3)(i). The NRC requests public comment on whether any applicant or licensee is committed to, and is using, a version of NQA–1 older than the 1994 Edition, and if so, what version the applicant or licensee is using.

NRC Question 2. *ASME BPV Code Case N–824.* The NRC is proposing to make ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' acceptable for use with conditions. The use of N–824, as conditioned, is considered a stop-gap improvement until ASME Section XI Appendix VIII Supplement 9 is developed and implemented. The NRC is considering whether ASME BPV Code Case N–824, as conditioned, should be mandatory because of the potential that licensees may continue to use less effective ASME Code Section XI Appendix III techniques for examinations of welds next to CASS material. Should ASME BPV Code Case N–824, as conditioned, be mandatory? What are the possible advantages and disadvantages of making N–824, as conditioned, mandatory?

VII. Plain Writing

The Plain Writing Act of 2010 (Pub. L. 111–274) requires Federal agencies to write documents in a clear, concise, and well-organized manner. The NRC has written this document to be consistent with the Plain Writing Act as well as the Presidential Memorandum, ''Plain Language in Government Writing,'' published June 10, 1998 (63 FR 31883). The NRC requests comment on this document with respect to the clarity and effectiveness of the language used.

VIII. Voluntary Consensus Standards

The National Technology Transfer and Advancement Act of 1995, Public Law 104–113 (NTTAA), and implementing guidance in U.S. Office of Management and Budget (OMB) Circular A–119 (February 10, 1998), requires that Federal agencies use technical standards that are developed or adopted by voluntary consensus standards bodies unless using such a standard is inconsistent with applicable law or is otherwise impractical. The NTTAA requires Federal agencies to use industry consensus standards to the extent practical; it does not require Federal agencies to endorse a standard in its entirety. Neither the NTTAA nor Circular A–119 prohibit an agency from adopting a voluntary consensus standard while taking exception to specific portions of the standard, if those provisions are deemed to be ''inconsistent with applicable law or otherwise impractical.'' Furthermore, taking specific exceptions furthers the Congressional intent of Federal reliance on voluntary consensus standards because it allows the adoption of substantial portions of consensus standards without the need to reject the standards in their entirety because of limited provisions that are not acceptable to the agency.

In this rulemaking, the NRC is continuing its existing practice of establishing requirements for the design, construction, operation, inservice inspection (examination) and inservice testing of nuclear power plants by approving the use of the latest editions and addenda of the ASME BPV and OM Codes (ASME Codes) in § 50.55a. The ASME Codes are voluntary consensus standards, developed by participants with broad and varied interests, in which all interested parties (including the NRC and licensees of nuclear power plants) participate. Therefore, the NRC's incorporation by reference of the ASME Codes is consistent with the overall objectives of the NTTAA and OMB Circular A–119.

As discussed in Section III of this statement of considerations, in this proposed rule the NRC is conditioning the use of certain provisions of the 2009 Addenda, 2010 Edition, 2011 Addenda, and the 2013 Edition to the ASME BPV Code, Section III, Division 1 and the ASME BPV Code, Section XI, Division 1, including NQA–1 (with conditions on its use), as well as the 2009 Edition and 2011 Addenda and 2012 Edition to the ASME OM Code and Code Cases N–770–2, N–729–4, and N–824. In addition, the proposed rule does not adopt (''excludes'') certain provisions of the ASME Codes and this statement of considerations, and in the regulatory and backfit analysis for this rulemaking. The NRC believes that this proposed rule complies with the NTTAA and OMB Circular A–119 despite these conditions and ''exclusions.''

If the NRC did not conditionally accept ASME editions, addenda, and code cases, the NRC would disapprove these entirely. The effect would be that licensees and applicants would submit a larger number of requests for use of alternatives under § 50.55a(z), requests for relief under § 50.55a(f) and (g), or requests for exemptions under § 50.12 and/or § 52.7. These requests would likely include broad-scope requests for approval to issue the full scope of the ASME Code editions and addenda which would otherwise be approved as proposed in this rulemaking (*i.e.,* the request would not be simply for approval of a specific ASME Code provision with conditions). These requests would be an unnecessary additional burden for both the licensee and the NRC, inasmuch as the NRC has already determined that the ASME Codes and Code Cases that are the subject of this rulemaking are acceptable for use (in some cases with conditions). For these reasons, the NRC concludes that this proposed rule's treatment of ASME Code editions and addenda, and code cases and any conditions placed on them does not conflict with any policy on agency use of consensus standards specified in OMB Circular A–119.

The NRC did not identify any other voluntary consensus standards developed by U.S. voluntary consensus standards bodies for use within the U.S. that the NRC could incorporate by reference instead of the ASME Codes. The NRC also did not identify any voluntary consensus standards developed by multinational voluntary consensus standards bodies for use on a multinational basis that the NRC could incorporate by reference instead of the ASME Codes. The NRC identified codes addressing the same subject as the ASME Codes for use in individual countries. At least one country, Korea, directly translated the ASME Code for use in that country. In other countries (*e.g.,* Japan), ASME Codes were the basis for development of the country's codes, but the ASME Codes were substantially modified to accommodate that country's regulatory system and reactor designs. Finally, there are countries (*e.g.,* the Russian Federation) where that country's code was developed without regard to the ASME Code. However, some of these codes may not meet the definition of a voluntary consensus standard because they were developed by the state rather than a voluntary consensus standards body. Evaluation by the NRC of the countries' codes to determine whether each code provides a comparable or enhanced level of safety when compared against the level of safety provided under the ASME Codes would require a significant expenditure of agency resources. This expenditure does not seem justified, given that substituting another country's code for the U.S. voluntary consensus standard does not appear to substantially further the apparent underlying objectives of the NTTAA.

In summary, this proposed rulemaking satisfies the requirements of the NTTAA and OMB Circular A–119.

IX. Incorporation by Reference—Reasonable Availability to Interested Parties

The NRC proposes to incorporate by reference seven recent editions and addenda to the ASME codes for nuclear power plants and a standard for quality assurance. The NRC is also proposing to incorporate by reference four ASME code cases. As described in the ''Background'' and ''Discussion'' sections of this notice, these materials provide rules for safety governing the design, fabrication, and inspection of nuclear power plant components.

The NRC is required by law to obtain approval for incorporation by reference from the Office of the Federal Register (OFR). The OFR's requirements for incorporation by reference are set forth in 1 CFR part 51. On November 7, 2014, the OFR adopted changes to its regulations governing incorporation by reference (79 FR 66267). The OFR regulations require an agency to include in a proposed rule a discussion of the ways that the materials the agency proposes to incorporate by reference are reasonably available to interested parties or how it worked to make those materials reasonably available to interested parties. The discussion in this section complies with the requirement for proposed rules as set forth in 10 CFR 51.5(a)(1).

The NRC considers ''interested parties'' to include all potential NRC stakeholders, not only the individuals and entities regulated or otherwise subject to the NRC's regulatory oversight. These NRC stakeholders are not a homogenous group but vary with respect to the considerations for determining reasonable availability. Therefore, the NRC distinguishes between different classes of interested parties for purposes of determining whether the material is ''reasonably available.'' The NRC considers the following to be classes of interested parties in NRC rulemakings with regard to the material to be incorporated by reference:

- Individuals and small entities regulated or otherwise subject to the NRC's regulatory oversight (this class also includes applicants and potential applicants for licenses and other NRC regulatory approvals) and who are subject to the material to be incorporated by reference by rulemaking. In this context, ''small entities'' has the same meaning as a ''small entity'' under 10 CFR 2.810.
- Large entities otherwise subject to the NRC's regulatory oversight (this class also includes applicants and potential applicants for licenses and other NRC regulatory approvals) and who are subject to the material to be incorporated by reference by rulemaking. In this context, ''large entities'' are those which do not qualify as a ''small entity'' under 10 CFR 2.810.
- Non-governmental organizations with institutional interests in the matters regulated by the NRC.
- Other Federal agencies, states, local governmental bodies (within the meaning of 10 CFR 2.315(c)).
- Federally-recognized and State-recognized [3] Indian tribes.
- Members of the general public (*i.e.,* individual, unaffiliated members of the public who are not regulated or otherwise subject to the NRC's regulatory oversight) who may wish to gain access to the materials which the NRC proposes to incorporate by reference by rulemaking in order to participate in the rulemaking.

The NRC makes the materials to be incorporated by reference available for inspection to all interested parties, by appointment, at the NRC Technical Library, which is located at Two White Flint North, 11545 Rockville Pike, Rockville, Maryland 20852; telephone: 301–415–7000; email: *Library.Resource@nrc.gov.*

Interested parties may purchase a copy of the materials from ASME at Three Park Avenue, New York, NY 10016, or at the ASME Web site *https://www.asme.org/shop/standards.* The materials are also accessible through third-party subscription services such as IHS (15 Inverness Way East, Englewood, CO 80112; *https://global.ihs.com*) and Thomson Reuters Techstreet (3916 Ranchero Dr., Ann Arbor, MI 48108; *http://www.techstreet.com*). The purchase prices for individual documents range from $225 to $720 and the cost to purchase all documents is approximately $9,000.

For the class of interested parties constituting members of the general public who wish to gain access to the materials to be incorporated by reference in order to participate in the rulemaking, the NRC recognizes that the $9,000 cost may be so high that the materials could be regarded as not reasonably available for purposes of commenting on this rulemaking, despite the NRC's actions to make the materials available at the NRC's PDR. Accordingly, the NRC sent a letter to the ASME requesting that they consider enhancing public access to these materials during the public comment period (ADAMS Accession No. ML15085A206). In an April 21, 2015, letter to the NRC, the ASME agreed to make the materials available online in a read-only electronic access format during the public comment period (ADAMS Accession No. ML15112A064). Therefore, the seven editions and addenda to the ASME codes for nuclear power plants, the ASME standard for quality assurance, and the four ASME code cases which the NRC proposes to incorporate by reference in this rulemaking are available in read-only format at the ASME Web site *http://go.asme.org/NRC.*

The NRC concludes that the materials the NRC proposes to incorporate by reference in this rulemaking are reasonably available to all interested parties because the materials are available to all interested parties in multiple ways and in a manner consistent with their interest in the materials.

X. Environmental Assessment and Final Finding of No Significant Environmental Impact

This proposed rule action is in accordance with the NRC's policy to incorporate by reference in § 50.55a new editions and addenda of the ASME BPV and OM Codes to provide updated rules for constructing and inspecting components and testing pumps, valves, and dynamic restraints (snubbers) in light-water nuclear power plants. The ASME Codes are national voluntary consensus standards and are required by the NTTAA to be used by government agencies unless the use of such a standard is inconsistent with applicable law or otherwise impractical. The National Environmental Policy Act (NEPA) requires Federal agencies to study the impacts of their ''major Federal actions significantly affecting the quality of the human environment,'' and prepare detailed statements on the environmental impacts of the proposed action and alternatives to the proposed action (42 U.S.C. Sec. 4332(C); NEPA Sec. 102(C)).

The NRC has determined under NEPA, as amended, and the NRC's

[3] State-recognized Indian tribes are not within the scope of 10 CFR 2.315(c). However, for purposes of the NRC's compliance with 1 CFR 51.5, ''interested parties'' includes a broad set of stakeholders, including State-recognized Indian tribes.

regulations in subpart A of 10 CFR part 51, that this proposed rule is not a major Federal action significantly affecting the quality of the human environment and, therefore, an environmental impact statement is not required. The rulemaking does not significantly increase the probability or consequences of accidents, no changes are being made in the types of effluents that may be released off-site, and there is no significant increase in public radiation exposure. The NRC estimates the radiological dose to plant personnel performing the inspections required by ASME BPV Code Case N–770–2 would be about 3 rem per plant over a 10-year interval, and a one-time exposure for mitigating welds of about 30 rem per plant. The NRC estimates the radiological dose to plant personnel performing the inspections required by ASME BPV Code Case N–729–4 would be about 3 rem per plant over a 10-year interval and a one-time exposure for mitigating welds of about 30 rem per plant. As required by 10 CFR part 20, and in accordance with current plant procedures and radiation protection programs, plant radiation protection staff will continue monitoring dose rates and would make adjustments in shielding, access requirements, decontamination methods, and procedures as necessary to minimize the dose to workers. The increased occupational dose to individual workers stemming from the ASME BPV Code Case N–770–2 and N–729–4 inspections must be maintained within the limits of 10 CFR part 20 and as low as reasonably achievable. Therefore, the NRC concludes that the increase in occupational exposure would not be significant. The proposed rule does not involve non-radiological plant effluents and has no other environmental impact. Therefore, no significant non-radiological impacts are associated with this action. The determination of this environmental assessment is that there will be no significant off-site impact to the public from this action.

XI. Paperwork Reduction Act Statement

This proposed rule contains new or amended collections of information subject to the Paperwork Reduction Act of 1995 (44 U.S.C. 3501 *et seq.*). This proposed rule has been submitted to the Office of Management and Budget for review and approval of the information collections.

Type of submission, new or revision: Revision.

The title of the information collection: Domestic Licensing of Production and Utilization Facilities: Incorporation by Reference of American Society of Mechanical Engineers Codes and Code Cases.

The form number if applicable: Not applicable.

How often the collection is required or requested: On occasion.

Who will be required or asked to respond: Power reactor licensees and applicants for power reactors under construction.

An estimate of the number of annual responses: 320.

The estimated number of annual respondents: 104.

An estimate of the total number of hours needed annually to comply with the information collection requirement or request: 121,600.

Abstract: This proposed rule is the latest in a series of rulemakings to amend the NRC's regulations to incorporate by reference revised and updated ASME codes for nuclear power plants. The number of operating nuclear power plants has decreased and the NRC has increased its estimate of the burden associated with developing alternative requests. Overall, the reporting burden for 10 CFR 50.55a has increased.

The U.S. Nuclear Regulatory Commission is seeking public comment on the potential impact of the information collections contained in this proposed rule and on the following issues:

1. Is the proposed information collection necessary for the proper performance of the functions of the NRC, including whether the information will have practical utility?
2. Is the estimate of the burden of the proposed information collection accurate?
3. Is there a way to enhance the quality, utility, and clarity of the information to be collected?
4. How can the burden of the proposed information collection on respondents be minimized, including the use of automated collection techniques or other forms of information technology?

A copy of the OMB clearance package and proposed rule is available in ADAMS (Accession Nos. ML14141A281 and ML14258B191) or may be viewed free of charge at the NRC's PDR, One White Flint North, 11555 Rockville Pike, Room O–1 F21, Rockville, MD 20852. You may obtain information and comment submissions related to the OMB clearance package by searching on *http://www.regulations.gov* under Docket ID NRC–2011–0088.

You may submit comments on any aspect of these proposed information collection(s), including suggestions for reducing the burden and on the previously stated issues, by the following methods:

- *Federal Rulemaking Web site:* Go to *http://www.regulations.gov* and search for Docket ID NRC–2011–0088.
- *Mail comments to:* FOIA, Privacy, and Information Collections Branch, Office of Information Services, Mail Stop: T–5 F53, U.S. Nuclear Regulatory Commission, Washington, DC 20555–0001 or to Vlad Dorjets, Desk Officer, Office of Information and Regulatory Affairs (3150–0011), NEOB–10202, Office of Management and Budget, Washington, DC 20503; telephone 202–395–7315, email: *oira_submission@omb.eop.gov.*

Submit comments by October 19, 2015. Comments received after this date will be considered if it is practical to do so, but the NRC staff is able to ensure consideration only for comments received on or before this date.

Public Protection Notification

The NRC may not conduct or sponsor, and a person is not required to respond to, a request for information or an information collection requirement unless the requesting document displays a currently valid OMB control number.

XII. Regulatory Analysis: Availability

The NRC has prepared a draft regulatory analysis on this proposed rule. The analysis examines the costs and benefits of the alternatives considered by the Commission. The NRC requests public comments on the draft regulatory analysis. Comments on the draft analysis may be submitted to the NRC by any method provided in the **ADDRESSES** section of this notice.

XIII. Backfitting and Issue Finality

Introduction

The NRC's Backfit Rule in § 50.109 states that the NRC shall require the backfitting of a facility only when it finds the action to be justified under specific standards stated in the rule. Section 50.109(a)(1) defines backfitting as the modification of or addition to systems, structures, components, or design of a facility; the design approval or manufacturing license for a facility; or the procedures or organization required to design, construct, or operate a facility. Any of these modifications or additions may result from a new or amended provision in the NRC's rules or the imposition of a regulatory position interpreting the NRC's rules that is either new or different from a previously applicable NRC position after issuance of the construction permit or the operating license or the design approval.

Section 50.55a requires nuclear power plant licensees to:

- Construct ASME BPV Code Class 1, 2, and 3 components in accordance with the rules provided in Section III, Division 1, of the ASME BPV Code (''Section III'').
- Inspect Class 1, 2, 3, Class MC, and Class CC components in accordance with the rules provided in Section XI, Division 1, of the ASME BPV Code (''Section XI'').
- Test Class 1, 2, and 3 pumps, valves, and dynamic restraints (snubbers) in accordance with the rules provided in the ASME OM Code.

This rulemaking proposes to incorporate by reference the 2009 Addenda, 2010 Edition, 2011 Addenda, and the 2013 Edition to the ASME BPV Code, Section III, Division 1 and ASME BPV Code, Section XI, Division 1, including NQA–1 (with conditions on its use), as well as the 2009 Edition and 2011 Addenda and 2012 Edition to the ASME OM Code and Code Cases N–770–2 and N–729–4.

The ASME BPV and OM codes are national consensus standards developed by participants with broad and varied interests, in which all interested parties (including the NRC and utilities) participate. A consensus process involving a wide range of stakeholders is consistent with the National Technology Transfer and Advancement Act, inasmuch as the NRC has determined that there are sound regulatory reasons for establishing regulatory requirements for design, maintenance, ISI, and IST by rulemaking. The process also facilitates early stakeholder consideration of backfitting issues. Thus, the NRC believes that the NRC need not address backfitting with respect to the NRC's general practice of incorporating by reference updated ASME Codes.

Overall Backfitting Considerations: Section III of the ASME BPV Code

Incorporation by reference of more recent editions and addenda of Section III of the ASME BPV Code does not affect a plant that has received a construction permit or an operating license or a design that has been approved. This is because the edition and addenda to be used in constructing a plant are, under § 50.55a, determined based on the date of the construction permit, and are not changed thereafter, except voluntarily by the licensee. The incorporation by reference of more recent editions and addenda of Section III ordinarily applies only to applicants after the effective date of the final rule incorporating these new editions and addenda. Thus, incorporation by reference of a more recent edition and addenda of Section III does not constitute ''backfitting'' as defined in § 50.109(a)(1).

Overall Backfitting Considerations: Section XI of the ASME BPV Code and the ASME OM Code

Incorporation by reference of more recent editions and addenda of Section XI of the ASME BPV Code and the ASME OM Code affects the ISI and IST programs of operating reactors. However, the Backfit Rule generally does not apply to incorporation by reference of later editions and addenda of the ASME BPV Code (Section XI) and OM Code. As previously mentioned, the NRC's longstanding regulatory practice has been to incorporate later versions of the ASME Codes into § 50.55a. Under § 50.55a, licensees shall revise their ISI and IST programs every 120 months to the latest edition and addenda of Section XI of the ASME BPV Code and the ASME OM Code incorporated by reference into § 50.55a 12 months before the start of a new 120-month ISI and IST interval. Thus, when the NRC approves and requires the use of a later version of the Code for ISI and IST, it is implementing this longstanding regulatory practice and requirement.

Other circumstances where the NRC does not apply the Backfit Rule to the approval and requirement to use later Code editions and addenda are as follows:

1. When the NRC takes exception to a later ASME BPV Code or OM Code provision but merely retains the current existing requirement, prohibits the use of the later Code provision, limits the use of the later Code provision, or supplements the provisions in a later Code. The Backfit Rule does not apply because the NRC is not imposing new requirements. However, the NRC explains any such exceptions to the Code in the Statement of Considerations and regulatory analysis for the rule.
2. When an NRC exception relaxes an existing ASME BPV Code or OM Code provision but does not prohibit a licensee from using the existing Code provision. The Backfit Rule does not apply because the NRC is not imposing new requirements.
3. Modifications and limitations imposed during previous routine updates of § 50.55a have established a precedent for determining which modifications or limitations are backfits, or require a backfit analysis (*e.g.,* final rule dated September 10, 2008 [73 FR 52731], and a correction dated October 2, 2008 [73 FR 57235]). The application of the backfit requirements to modifications and limitations in the current rule are consistent with the application of backfit requirements to modifications and limitations in previous rules.

The incorporation by reference and adoption of a requirement mandating the use of a later ASME BPV Code or OM Code may constitute backfitting in some circumstances. In these cases, the NRC would perform a backfit analysis or documented evaluation in accordance with § 50.109. These include the following:

1. When the NRC endorses a later provision of the ASME BPV Code or OM Code that takes a substantially different direction from the existing requirements, the action is treated as a backfit (*e.g.,* 61 FR 41303 [August 8, 1996]).
2. When the NRC requires implementation of a later ASME BPV Code or OM Code provision on an expedited basis, the action is treated as a backfit. This applies when implementation is required sooner than it would be required if the NRC simply endorsed the Code without any expedited language (*e.g.,* 64 FR 51370 [September 22, 1999]).
3. When the NRC takes an exception to an ASME BPV Code or OM Code provision and imposes a requirement that is substantially different from the existing requirement as well as substantially different from the later Code (*e.g.,* 67 FR 60529 [September 26, 2002]).

Detailed Backfitting Discussion: Proposed Changes Beyond Those Necessary To Incorporate by Reference the New ASME BPV and OM Code Provisions

This section discusses the backfitting considerations for all the proposed changes to § 50.55a that go beyond the minimum changes necessary and required to adopt the new ASME Code Addenda into § 50.55a.

ASME BPV Code, Section III

1. Revise § 50.55a(b)(1)(ii), ''Weld leg dimensions,'' to clarify rule language and add Table 1, which clarifies prohibited Section III provisions in tabular form for welds with leg size less than 1.09 t_n. This proposed change would not alter the original intent of this requirement and, therefore, would not impose a new requirement. Therefore, this proposed change is not a backfit.
2. Revise § 50.55a(b)(1)(iv), ''Section III condition: Quality assurance,'' to require that when applying editions and addenda later than the 1989 Edition of

Section III, the requirements of NQA–1, 1983 Edition through the 1994 Edition, 2008 Edition, and the 2009–1a Addenda are acceptable for use, provided that the edition and addenda of NQA–1 specified in either NCA–4000 or NCA–7000 is used in conjunction with the administrative, quality and technical provisions contained in the edition and addenda of Section III being used. This proposed revision clarifies the current requirements, and is considered to be consistent with the meaning and intent of the current requirements, and therefore is not considered to result in a change in requirements. Therefore, this proposed change is not a backfit.

3. Add a new proposed condition as § 50.55a(b)(1)(viii), ''Use of ASME Certification Marks,'' to allow licensees to use either the ASME BPV Code Symbol Stamp or ASME Certification Mark with the appropriate certification designator and class designator as specified in the 2013 Edition through the latest edition and addenda incorporated by reference in 10 CFR 50.55a. This proposed condition would not result in a change in requirements previously approved in the Code and, therefore, is not a backfit.

ASME BPV Code, Section XI

1. Revise § 50.55a(b)(2)(vi), ''Effective Edition and Addenda of Subsection IWE and Subsection IWL, Section XI;'' to clarify that the provision applies only to the class of licensees of operating reactors that were required by previous versions of § 50.55a to develop, implement a containment inservice inspection program in accordance with Subsection IWE and Subsection IWL, and complete an expedited examination of containment during the 5-year period from September 9, 1996, to September 9, 2001. This proposed revision clarifies the current requirements, is considered to be consistent with the meaning and intent of the current requirements, and is not considered to result in a change in requirements. Therefore, this proposed change is not a backfit.

2. Revise § 50.55a(b)(2)(viii), ''Examination of concrete containments,'' so that when using the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL, the conditions in 10 CFR 50.55a(b)(2)(viii)(E) do not apply, but the proposed conditions in new 10 CFR 50.55a(b)(2)(viii)(H) and 10 CFR 50.55a(b)(2)(viii)(I) do apply. This proposed revision would not require 10 CFR 50.55a(b)(2)(viii)(E) to be used when following the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL because most of its requirements have been included in IWL–2512, ''Inaccessible Areas.'' Therefore, this proposed change is not a backfit because the requirements have not changed. The revision to add the condition in 10 CFR 50.55a(b)(2)(viii)(H) captures the reporting requirements of the current 10 CFR 50.55a(b)(2)(viii)(E) which were not included in IWL–2512. Therefore, this proposed change is not a backfit because the requirements have not changed. The revision to add the condition in 10 CFR 50.55a(b)(2)(viii)(I) addresses a new code provision in IWL–2512(b) for evaluation of below-grade concrete surfaces during the period of extended operation of a renewed license. The condition assures consistency with the GALL Report and applies to plants going forward using the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWL. The requirements would remain unchanged from those of the GALL Report and, therefore, this change is not a backfit.

3. Revise § 50.55a(b)(2)(ix), ''Examination of metal containments,'' to extend the applicability of the existing conditions in § 50.55a(b)(2)(ix)(A)(2), § 50.55a(b)(2)(ix)(B), and § 50.55a(b)(2)(ix)(J) to the 2007 Edition with 2009 Addenda through the 2013 Edition of Subsection IWE. This proposed condition would not result in a change to current requirements, and is therefore not a backfit.

4. Revise § 50.55a(b)(2)(x), ''Section XI condition: Quality assurance,'' to require that when applying the editions and addenda later than the 1989 Edition of ASME BPV Code, Section XI, the requirements of NQA–1, 1983 Edition through the 1994 Edition, the 2008 Edition, and the 2009–1a Addenda specified in either IWA–1400 or Table IWA 1600–1, ''Referenced Standards and Specifications,'' of that edition and addenda of Section XI are acceptable for use, provided the licensee uses its appendix B to 10 CFR part 50 quality assurance program in conjunction with Section XI requirements. This proposed revision clarifies the current requirements, which the NRC considers to be consistent with the meaning and intent of the current requirements. Therefore, the NRC does not consider the clarification to be a change in requirements. Therefore, this proposed change is not a backfit.

5. Add a new proposed condition as § 50.55a(b)(2)(xviii)(D), ''NDE personnel certification: Fourth provision;'' to prohibit the use of Appendix VII and subarticle VIII–2200 of the 2011 Addenda and 2013 Edition of Section XI of the ASME BPV Code. Licensees would be required to implement Appendix VII and subarticle VIII–2200 of the 2010 Edition of Section XI. This condition does not constitute a change in NRC position because the use of the subject provisions is not currently allowed by § 50.55a. Therefore, the addition of this new proposed condition is not a backfit.

6. Revise § 50.55a(b)(2)(xxi)(A), ''Table IWB–2500–1 examination requirements; First provision,'' to modify the standard for visual magnification resolution sensitivity and contrast for visual examinations of Examination Category B–D components, making the rule conform with ASME BPV Code, Section XI requirements for VT–1 examinations. This proposed revision removes a condition that was in addition to the ASME Code requirements and does not impose a new requirement. Therefore, this change is not a backfit.

7. Add a new proposed condition as § 50.55a(b)(2)(xxx), ''Steam Generator Preservice Examinations;'' to require that instead of the preservice inspection requirements of Section XI, IWB–2200(c), a full length examination of 100 percent of the tubing in each newly installed steam generator shall be performed prior to plant startup. This proposed condition provides a clarification consistent with industry guidelines and the NRC staff position in SRP Section 5.4.2.2. Therefore, the addition of this new proposed condition is not a backfit.

8. Add a new proposed condition as § 50.55a(b)(2)(xxxi), ''Mechanical clamping devices;'' to prohibit the use of mechanical clamping devices in accordance with IWA–4131.1(c) in the 2010 Edition and IWA–4131.1(d) in the 2011 Addenda through 2013 Edition on small item Class 1 piping and portions of a piping system that forms the containment boundary. This condition does not constitute a change in NRC position and would not affect licensees because the use of the subject provisions is not currently allowed by § 50.55a. Therefore, the addition of this new proposed condition is not a backfit.

9. Add a new proposed condition as § 50.55a(b)(2)(xxxii), ''Summary Report submittal;'' to clarify that licensees using the 2010 Edition or later editions and addenda of Section XI must continue to submit to the NRC the Preservice and Inservice Summary Reports required by IWA–6240 of the 2009 addenda of Section XI. This proposed condition would not result in a change in NRC's requirements insomuch as these reports have been required in the 2009 Addenda of Section XI and all previous editions and

addenda. Therefore, the addition of this new proposed condition is not a backfit.

10. Add a new proposed condition as § 50.55a(b)(2)(xxxiii), ''Risk-Informed allowable pressure;'' to prohibit the use of ASME BPV Code, Section XI, Appendix G, Paragraph G–2216. The use of Paragraph G–2216 is not currently allowed by § 50.55a. Therefore, the proposed condition does not constitute a new or changed NRC position on the lack of acceptability of Paragraph G–2216. Therefore, the addition of this new proposed condition is not a backfit.

11. Add a new proposed condition as § 50.55a(b)(2)(xxxiv), ''Disposition of flaws in Class 3 components;'' to require that when using the 2013 Edition of the ASME BPV Code, Section XI, the licensee shall use the acceptance standards of IWD–3510 for the disposition of flaws in Category D–A components. The condition is imposed to provide clarification and consistency in requirements between IWD–3410 and IWD–3510. This proposed change would not alter the original intent of this requirement and, therefore, would not impose a new requirement. This proposed change is not a backfit.

12. Add a new proposed condition as § 50.55a(b)(2)(xxxv), ''Use of RT_{T0} in the K_{Ia} and K_{Ic} equations;'' to specify that when licensees use ASME BPV Code, Section XI 2013 Edition Nonmandatory Appendix A paragraph A–4200, if T_0 is available, then RT_{T0} may be used in place of RT_{NDT} for applications using the K_{Ic} equation and the associated K_{Ic} curve, but not for applications using the K_{Ia} equation and the associated K_{Ia} curve. Conditions on the use of ASME BPV Code, Section XI, Nonmandatory Appendices do not constitute backfitting inasmuch as those provisions apply to voluntary actions initiated by the licensee to use the ''nonmandatory compliance'' provisions in these Appendices of the proposed rule.

13. Add a new proposed condition as § 50.55a(b)(2)(xxxvi), ''Fracture toughness of irradiated materials;'' to require licensees using ASME BPV Code, Section XI 2013 Edition Nonmandatory Appendix A paragraph A–4400, to obtain NRC approval before using irradiated T_0 and the associated RT_{T0} in establishing fracture toughness of irradiated materials. Conditions on the use of ASME BPV Code, Section XI, Nonmandatory Appendices do not constitute backfitting inasmuch as those provisions apply to voluntary actions initiated by the licensee to use the ''nonmandatory compliance'' provisions in these Appendices of the proposed rule.

14. Add a new proposed condition as § 50.55a(b)(2)(xxxvii), ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' to allow the use of the code case as conditioned. Conditions on the use of ASME BPV Code Case N–824 do not constitute backfitting, inasmuch as the use of this code case is not required by the NRC but instead is an alternative which may be voluntarily used by the licensee (*i.e.,* a ''voluntary alternative'').

ASME OM Code

1. Add a new proposed condition as § 50.55a(b)(3)(ii)(A) to require that licensees evaluate the adequacy of the diagnostic test interval for each MOV and adjust the interval as necessary, but not later than 5 years or three refueling outages (whichever is longer) from initial implementation of Appendix III of the ASME OM Code. This proposed condition represents an exception to a later OM Code provision but merely retains the current NRC requirement in RG 1.192, and is therefore not a backfit because the NRC is not imposing a new requirement.

2. Add a new proposed condition as § 50.55a(b)(3)(ii)(B) to require that licensees ensure that the potential increase in core damage frequency and large early release frequency associated with the extension is acceptably small when extending exercise test intervals for high risk MOVs beyond a quarterly frequency. This proposed condition represents an exception to a later OM Code provision but merely retains the current NRC requirement in RG 1.192, and is therefore not a backfit because the NRC is not imposing a new requirement.

3. Add a new proposed condition as § 50.55a(b)(3)(ii)(C) to require, when applying Appendix III to the ASME OM Code, that licensees categorize MOVs according to their safety significance using the methodology described in ASME OM Code Case OMN–3 subject to the conditions discussed in RG 1.192, or using an MOV risk ranking methodology accepted by the NRC on a plant-specific or industry-wide basis in accordance with the conditions in the applicable safety evaluation. This proposed condition represents an exception to a later OM Code provision but merely retains the current NRC requirement in RG 1.192, and is therefore not a backfit because the NRC is not imposing a new requirement.

4. Add a new proposed condition as § 50.55a(b)(3)(ii)(D) to require that, when applying Paragraph III–3600, ''MOV Exercising Requirements,'' of Appendix III to the OM Code, licensees shall verify that the stroke time of the MOV satisfies the assumptions in the plant safety analyses. This proposed condition retains the MOV stroke time requirement that was specified in previous editions and addenda of the ASME OM Code. The retention of this requirement is not a backfit.

5. Add new proposed conditions as § 50.55a(b)(3)(iii)(A) through § 50.55a(b)(3)(iii)(D), ''OM condition: New Reactors;'' to apply specific conditions for IST programs applicable to licensees of new nuclear power plants in addition to the provisions of the ASME OM Code as incorporated by reference with conditions in § 50.55a. Licensees of ''new reactors'' are, as identified in the proposed paragraph: (i) Holders of operating licenses for nuclear power reactors that received construction permits under this part on or after the date 12 months after the effective date of this rulemaking and (ii) holders of COLs issued under 10 CFR part 52, whose initial fuel loading occurs on or after the date 12 months after the effective date of this rulemaking. This implementation schedule for new reactors is consistent with the NRC regulations in § 50.55a(f)(4)(i). These proposed conditions represent an exception to a later OM Code provision but merely retain the current NRC requirement, and are therefore not a backfit because the NRC is not imposing a new requirement.

6. Revise § 50.55a(b)(3)(iv), ''OM condition: Check valves (Appendix II),'' to specify that Appendix II, ''Check Valve Condition Monitoring Program,'' of the OM Code, 2003 Addenda through the 2012 Edition, is acceptable for use without conditions with the clarifications that (1) the maximum test interval allowed by Appendix II for individual check valves in a group of two valves or more must be supported by periodic testing of a sample of check valves in the group during the allowed interval and (2) the periodic testing plan must be designed to test each valve of a group at approximate equal intervals not to exceed the maximum requirement interval. The regulation is being revised to extend the applicability of this existing NRC condition on the OM Code to the 2012 Edition of the OM Code. This does not represent a change in the NRC's position that the condition is needed with respect to the OM Code. Therefore, this proposed condition is not a backfit.

7. Add a new proposed condition as § 50.55a(b)(3)(vii), ''OM condition: Subsection ISTB;'' to prohibit the use of Subsection ISTB in the 2011 Addenda to the ASME OM Code because the complete set of planned Code

modifications to support the changes to the comprehensive pump test acceptance criteria was not made in that addenda. This proposed condition represents an exception to a later OM Code provision but merely limits the use of the later Code provision, and is therefore not a backfit because the NRC is not imposing a new requirement.

8. Add a new proposed condition as § 50.55a(b)(3)(viii), ''OM condition: Subsection ISTE;'' to allow licensees to implement Subsection ISTE, ''Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants,'' in the ASME OM Code, 2009 Edition, 2011 Addenda and 2012 Edition, where the licensee has obtained authorization to implement Subsection ISTE as an alternative to the applicable IST requirements in the ASME OM Code on a case-by-case basis in accordance with § 50.55a(z). This proposed condition represents an exception to a later OM Code provision but merely limits the use of the later Code provision, and is therefore not a backfit because the NRC is not imposing a new requirement.

9. Add a new proposed condition as § 50.55a(b)(3)(ix), ''OM Condition: Subsection ISTF;'' to specify that licensees applying Subsection ISTF, 2012 Edition, shall satisfy the requirements of Mandatory Appendix V, ''Pump Periodic Verification Test Program,'' of the ASME OM Code, 2012 Edition. The proposed condition also specifies that Subsection ISTF, 2011 Addenda, is not acceptable for use. This proposed condition represents an exception to a later OM Code provision but merely limits the use of the later Code provision, and is therefore not a backfit because the NRC is not imposing a new requirement.

10. Add a new proposed condition as § 50.55a(b)(3)(x), ''OM condition: ASME OM Code Case OMN–20,'' to allow licensees to implement ASME OM Code Case OMN–20, ''Inservice Test Frequency,'' in the ASME OM Code, 2012 Edition. This proposed condition allows voluntary action initiated by the licensee to use the code case and is, therefore, not a backfit.

11. Add a new proposed condition as § 50.55a(b)(3)(xi), ''OM condition: Valve Position Indication,'' to specify that when implementing ASME OM Code, Subsection ISTC–3700, ''Position Verification Testing,'' licensees shall supplement the ASME OM Code provisions as necessary to verify that valve operation is accurately indicated. This proposed condition clarifies the current requirements, and is considered to be consistent with the meaning and intent of the current requirements, and therefore is not considered to result in a change in requirements. As such, this proposed condition is not a backfit.

12. Revise § 50.55a(f), ''Inservice testing requirements,'' to clarify that the ASME OM Code includes provisions for preservice testing of components as part of its overall provisions for IST programs. No expansion of IST program scope is intended by this clarification. This proposed condition would not result in a change in requirements previously approved in the Code and is, therefore, not a backfit.

13. Revise § 50.55a(f)(3)(iii)(A), ''Class 1 pumps and valves: First provision,'' to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6. This proposed condition would not result in a change in requirements previously approved in the Code and is, therefore, not a backfit.

14. Revise § 50.55a(f)(3)(iii)(B), ''Class 1 pumps and valves: Second provision,'' to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6. This proposed condition would not result in a change in requirements previously approved in the Code and is, therefore, not a backfit.

15. Revise § 50.55a(f)(3)(iv)(A), ''Class 2 and 3 pumps and valves: First provision;'' to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(A) for Class 1 pumps and valves. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6. This proposed condition would not result in a change in requirements previously approved in the Code and is, therefore, not a backfit.

16. Revise § 50.55a(f)(3)(iv)(B), ''Class 2 and 3 pumps and valves: Second provision,'' to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code and not covered by paragraph (f)(3)(iii)(B) for Class 1 pumps and valves. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6. This proposed condition would not result in a change in requirements previously approved in the Code, and is therefore not a backfit.

17. Revise § 50.55a(f)(4), ''Inservice testing standards for operating plants;'' to state that the paragraph is applicable to pumps and valves that are within the scope of the ASME OM Code. This will align the scope of pumps and valves for inservice testing with the scope defined in the ASME OM Code and in SRP Section 3.9.6. This proposed condition would not result in a change in requirements previously approved in the Code, and is therefore not a backfit.

ASME BPV Code Case N–729–4

Revise § 50.55a(g)(6)(ii)(D), ''Reactor vessel head inspections'':

On June 22, 2012, the ASME approved the fourth revision of ASME BPV Code Case N–729, (N–729–4). The NRC proposes to update the requirements of § 50.55a(g)(6)(ii)(D) to require licensees to implement ASME BPV Code Case N–729–4, with conditions. The ASME BPV Code Case N–729–4 contains similar requirements as N–729–1; however, N–729–4 also contains new requirements to address previous NRC conditions, including changes to inspection frequency and qualifications. The new NRC conditions on the use of ASME BPV Code Case N–729–4 address operational experience, clarification of implementation, and the use of alternatives to the code case.

The current regulatory requirements for the examination of pressurized water reactor upper RPV heads that use nickel-alloy materials are provided in § 50.55a(g)(6)(ii)(D). This section was first created by rulemaking, dated September 10, 2008, (73 FR 52730) to require licensees to implement ASME BPV Code Case N–729–1, with conditions, instead of the inspections previously required by the ASME BPV Code, Section XI. The action did constitute a backfit; however, NRC concluded that imposition of ASME BPV Code Case N–729–1, as conditioned, constituted an adequate protection backfit.

The GDC for nuclear power plants (appendix A to 10 CFR part 50) or, as appropriate, similar requirements in the licensing basis for a reactor facility, provide bases and requirements for NRC assessment of the potential for, and consequences of, degradation of the reactor coolant pressure boundary (RCPB). The applicable GDC include GDC 14 (Reactor Coolant Pressure Boundary), GDC 31 (Fracture Prevention of Reactor Coolant Pressure Boundary), and GDC 32 (Inspection of Reactor Coolant Pressure Boundary). General Design Criterion 14 specifies that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. General Design Criterion 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. General Design Criterion 32 specifies that components that are part of the RCPB have the capability of being periodically inspected to assess their structural and leak tight integrity.

The NRC concludes that ASME BPV Code Case N–729–4, as conditioned, shall be mandatory in order to ensure that the requirements of the GDC are satisfied. Imposition of ASME BPV Code Case N–729–4, with conditions, ensures that the ASME Code-allowable limits will not be exceeded, leakage will likely not occur and potential flaws will be detected before they challenge the structural or leak tight integrity of the reactor pressure vessel upper head within current nondestructive examination limitations. The NRC concludes that the regulatory framework for providing adequate protection of public health and safety is accomplished by the incorporation of ASME BPV Code Case N–729–4 into § 50.55a, as conditioned. All current licensees of U.S. pressurized water reactors will be required to implement ASME BPV Code Case N–729–4, as conditioned. The Code Case provisions on examination requirements for reactor pressure vessel upper heads are essentially the same as those established under ASME BPV Code Case N–729–1, as conditioned. One exception is the condition in § 50.55a(g)(6)(ii)(D)(3), which will require, for upper heads with Alloy 600 penetration nozzles, that bare metal visual examinations be performed each outage in accordance with Table 1 of ASME BPV Code Case N–729–4. Accordingly, the NRC imposition of the ASME BPV Code Case N–729–4, as conditioned, may be deemed to be a modification of the procedures to operate a facility resulting from the imposition of the new regulation, and as such, this rulemaking provision may be considered backfitting under § 50.109(a)(1).

The NRC continues to find that inspections of reactor pressure vessel upper heads, their penetration nozzles, and associated partial penetration welds are necessary for adequate protection of public health and safety and that the requirements of ASME BPV Code Case N–729–4, as conditioned, represent an acceptable approach, developed, in part, by a voluntary consensus standards organization for performing future inspections. The NRC concludes that approval of ASME BPV Code Case N–729–4, as conditioned, by incorporation by reference of the Code Case into § 50.55a, is necessary to ensure that the facility provides adequate protection to the health and safety of the public and constitutes a redefinition of the requirements necessary to provide reasonable assurance of adequate protection of public health and safety. Therefore, a backfit analysis need not be prepared for this portion of the proposed rule in accordance with § 50.109(a)(4)(ii) and § 50.109(a)(4)(iii).

ASME BPV Code Case N–770–2

Revise § 50.55a(g)(6)(ii)(F), ''Examination requirements for Class 1 piping and nozzle dissimilar metal butt welds'':

On June 9, 2011, the ASME approved the second revision of ASME BPV Code Case N–770, (N–770–2). The NRC proposes to update the requirements of § 50.55a(g)(6)(ii)(F) to require licensees to implement ASME BPV Code Case N–770–2, with conditions. The ASME BPV Code Case N–770–2 contains similar baseline and ISI requirements for unmitigated nickel-alloy butt welds, and preservice and ISI requirements for mitigated butt welds as N–770–1. However, N–770–2 also contains new requirements for optimized weld overlays, a specific mitigation technique and volumetric inspection coverage. Further, the NRC conditions on the use of ASME BPV Code Case N–770–2 have been modified to address the changes in the code case, clarify inspection coverage requirements and require the development of inspection qualifications to allow complete weld inspection coverage in the future.

The current regulatory requirements for the examination of ASME Class 1 piping and nozzle dissimilar metal butt welds that use nickel-alloy materials is provided in § 50.55a(g)(6)(ii)(F). This section was first created by rulemaking, dated June 21, 2011 (76 FR 36232), to require licensees to implement ASME BPV Code Case N–770–1, with conditions. The NRC added § 50.55a(g)(6)(ii)(F) to require licensees to implement ASME BPV Code Case N–770–1, with conditions, instead of the inspections previously required by the ASME BPV Code, Section XI. The action did constitute a backfit; however, the NRC concluded that imposition of ASME BPV Code Case N–770–1, as conditioned, constituted an adequate protection backfit.

The GDC for nuclear power plants (appendix A to 10 CFR part 50) or, as appropriate, similar requirements in the licensing basis for a reactor facility, provide bases and requirements for NRC assessment of the potential for, and consequences of, degradation of the RCPB. The applicable GDC include GDC 14 (Reactor Coolant Pressure Boundary), GDC 31 (Fracture Prevention of Reactor Coolant Pressure Boundary) and GDC 32 (Inspection of Reactor Coolant Pressure Boundary). General Design Criterion 14 specifies that the RCPB be designed, fabricated, erected, and tested so as to have an extremely low probability of abnormal leakage, of rapidly propagating failure, and of gross rupture. General Design Criterion 31 specifies that the probability of rapidly propagating fracture of the RCPB be minimized. General Design Criterion 32 specifies that components that are part of the RCPB have the capability of being periodically inspected to assess their structural and leak tight integrity.

The NRC concludes that ASME BPV Code Case N–770–2, as conditioned, must be imposed in order to ensure that the requirements of the GDC are satisfied. Imposition of ASME BPV Code Case N–770–2, with conditions, ensures that the requirements of the GDC are met for all mitigation techniques currently in use for Alloy 82/182 butt welds because ASME Code-allowable limits will not be exceeded, leakage would likely not occur and potential flaws will be detected before they challenge the structural or leak tight integrity of piping welds. All current licensees of U.S. pressurized water reactors will be required to implement ASME BPV Code Case N–770–2, as conditioned. The Code Case provisions on examination requirements for ASME Class 1 piping and nozzle nickel-alloy dissimilar metal butt welds are somewhat different from those established under ASME BPV Code Case N–770–1, as conditioned, and will require a licensee to modify its procedures for inspection of ASME Class 1 nickel-alloy welds to meet these requirements. Accordingly, the NRC imposition of the ASME BPV Code Case N–770–2, as conditioned, may be deemed to be a modification of the procedures to operate a facility resulting from the imposition of the new regulation, and as such, this rulemaking provision may be considered backfitting under § 50.109(a)(1).

The NRC continues to find that ASME Class 1 nickel-alloy dissimilar metal weld inspections are necessary for adequate protection of public health and safety, and that the requirements of ASME BPV Code Case N–770–2, as conditioned, represent an acceptable approach developed by a voluntary consensus standards organization for performing future ASME Class 1 nickel-alloy dissimilar metal weld inspections. The NRC concludes that approval of ASME BPV Code Case N–770–2, as conditioned, by incorporation by reference of the Code Case into § 50.55a, is necessary to ensure that the facility provides adequate protection to the health and safety of the public and constitutes a redefinition of the requirements necessary to provide reasonable assurance of adequate protection of public health and safety. Therefore, a backfit analysis need not be prepared for this portion of the proposed rule in accordance with § 50.109(a)(4)(ii) and § 50.109(a)(4)(iii).

Conclusion

The NRC finds that incorporation by reference into § 50.55a of the 2009 Addenda through 2013 Edition of Section III, Division 1, of the ASME BPV Code subject to the identified conditions; the 2009 Addenda through 2013 Edition of Section XI, Division 1, of the ASME BPV Code, subject to the identified conditions; and the 2009 Edition through the 2012 Edition of the ASME OM Code subject to the identified conditions does not constitute backfitting or represent an inconsistency with any issue finality provisions in 10 CFR part 52.

The NRC finds that the incorporation by reference of Code Cases N–824 and OMN–20 does not constitute backfitting or represent an inconsistency with any issue finality provisions in 10 CFR part 52.

The NRC finds that the inclusion of a new condition on Code Case N–729–4 and a new condition on Code Case N–770–2 constitutes backfitting necessary for adequate protection.

XIV. Regulatory Flexibility Certification

Under the Regulatory Flexibility Act of 1980 (5 U.S.C. 605(b)), the NRC certifies that this proposed rule does not impose a significant economical impact on a substantial number of small entities. This proposed rule affects only the licensing and operation of commercial nuclear power plants. A licensee who is a subsidiary of a large entity does not qualify as a small entity. The companies that own these plants are not ''small entities'' as defined in the Regulatory Flexibility Act or the size standards established by the NRC (10 CFR 2.810), as the companies:

- Provide services that are not engaged in manufacturing, and have average gross receipts of more than $6.5 million over their last 3 completed fiscal years, and have more than 500 employees;
- Are not governments of a city, county, town, township or village;
- Are not school districts or special districts with populations of less than 50; and
- Are not small educational institutions.

XV. Availability of Documents

The NRC is making the documents identified in Table 1 available to interested persons through one or more of the following methods, as indicated. To access documents related to this action, see the **ADDRESSES** section of this notice.

TABLE 1—AVAILABILITY OF DOCUMENTS

Document	ADAMS Accession No.
Proposed Rule Documents:	
Regulatory Analysis (includes backfitting discussion in Appendix A)	ML14170B104.
Related Documents:	
Fatigue and Fracture Mechanics: 33rd Volume, ASTM STP 1417, W.G. Reuter and R.S. Piascik, Eds., ASTM International, West Conshohocken, PA, 2002.	
''Final Results from the CARINA Project on Crack Initiation and Arrest of Irradiated German RPV Steels for Neutron Fluences in the Upper Bound,'' by AREVA at the 26th Symposium on Effects of Radiation on Nuclear Materials (June 12–13, 2013, Indianapolis, IN, USA).	
Letter from Brian Thomas, NRC, to Michael Merker, ASME; ''Public Access to Material the NRC Seeks to Incorporate by Reference into its Regulations;'' April 9, 2015.	ML15085A206.
Letter from Michael Merker, ASME, to Brian Thomas, NRC; April 21, 2015	ML15112A064.
Licensee Event Report 50–338/2012–001–00	ML12151A441.
NUREG–0800, ''Standard Review Plan for the Review of Safety Analysis Reports for Nuclear Power Plants, LWR Edition''.	ML070660036.
NUREG–0800, Section 3.9.6, Revision 3, ''Functional Design, Qualification, and Inservice Testing Programs for Pumps, Valves, and Dynamic Restraints,'' March 2007.	ML070720041.
NUREG–0800, Section 5.4.2.2, Revision 1, ''Steam Generator Tube Inservice Inspection,'' July 1981	ML052340627.
NUREG–1482, Revision 2, ''Guidelines for Inservice Testing at Nuclear Power Plants: Inservice Testing of Pumps and Valves and Inservice Examination and Testing of Dynamic Restraints (Snubbers) at Nuclear Power Plants,'' October 2013.	ML13295A020.
NUREG–1801, Revision 2, ''Generic Aging Lessons Learned (GALL) Report,'' December 2010	ML103490041.
NUREG–1950, ''Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG–1801 and NUREG–1800,'' April 2011.	ML11116A062.
NUREG/CR–6860, ''An Assessment of Visual Testing,'' November 2004	ML043630040.
NUREG/CR–6933, ''Assessment of Crack Detection in Heavy-Walled Cast Stainless Steel Piping Welds Using Advanced Low-Frequency Ultrasonic Methods,'' March 2007.	ML071020410 and ML071020414.
NUREG/CR–7122, ''An Evaluation of Ultrasonic Phased Array Testing for Cast Austenitic Stainless Steel Pressurizer Surge Line Piping Welds,'' March 2012.	ML12087A004.
NRC Generic Letter 90–05, ''Guidance for Performing Temporary Non-Code Repair of ASME Code Class 1, 2, and 3 Piping (Generic Letter 90–05),'' June 1990.	ML031140590.
NRC Meeting Summary of June 5–7, 2013, Annual Materials Programs Technical Information Exchange Public Meeting.	ML14003A230.
NRC Memorandum, ''Consolidation of SECY–94–084 and SECY–95–132,'' July 24, 1995	ML003708048.
NRC Memorandum, ''Staff Requirements—Affirmation Session, 11:30 a.m., Friday, September 10, 1999, Commissioners' Conference Room, One White Flint North, Rockville, Maryland (Open to Public Attendance),'' September 10, 1999.	ML003755050.
NRC Regulatory Guide 1.28, Revision 4, ''Quality Assurance Program Criteria (Design and Construction),'' June 2010.	ML100160003.
NRC Regulatory Guide 1.83, Revision 1, ''Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes,'' July 1975 (withdrawn in 2009).	ML003740256.
NRC Regulatory Guide 1.147, Revision 17, ''Inservice Inspection Code Case Acceptability, ASME Section XI, Division 1,'' August 2014.	ML13339A689.

TABLE 1—AVAILABILITY OF DOCUMENTS—Continued

Document	ADAMS Accession No.
NRC Regulatory Guide 1.174, Revision 2, ''An Approach for Using Probabilistic Risk Assessment in Risk-Informed Decisions on Plant-Specific Changes to the Licensing Basis,'' May 2011.	ML100910006.
NRC Regulatory Guide 1.175, ''An Approach for Plant-Specific, Risk-Informed Decisionmaking: Inservice Testing,'' August 1998.	ML003740149.
NRC Regulatory Guide 1.192, Revision 1, ''Operation and Maintenance Code Case Acceptability, ASME OM Code,'' August 2014.	ML13340A034.
NRC Regulatory Guide 1.200, Revision 2, ''An Approach for Determining the Technical Adequacy of Probabilistic Risk Assessment Results for Risk-Informed Activities,'' March 2009.	ML090410014.
NRC Regulatory Guide 1.201, Revision 1, ''Guidelines for Categorizing Structures, Systems, and Components in Nuclear Power Plants According to Their Safety Significance,'' May 2006.	ML061090627.
NRC Regulatory Information Conference, Recent Operating Reactors Materials Issues, Presentation Materials, 2013.	*http://www.nrc.gov/public-involve/conference-symposia/ric/past/2013/docs/abstracts/sessionabstract-19.html.*
Relief Request REP–1 U2, Revision 2	ML13232A308.
SECY–90–016, ''Evolutionary Light Water Reactor (LWR) Certification Issues and Their Relationship to Current Regulatory Requirements''.	ML003707849.
SECY–93–087, ''Policy, Technical, and Licensing Issues Pertaining to Evolutionary and Advanced Light-Water Reactor (ALWR) Designs''.	ML003708021.
SECY–94–084, ''Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems in Passive Plant Designs''.	ML003708068.
SECY–95–132, ''Policy and Technical Issues Associated with the Regulatory Treatment of Non-Safety Systems (RTNSS) in Passive Plant Designs (SECY–94–084)''.	ML003708005.
ASME Codes, Standards, and Code Cases:	
ASME BPV Code, Section III, Division 1: 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition.	*http://go.asme.org/NRC.*
ASME BPV Code, Section XI, Division 1: 2009 Addenda, 2010 Edition, 2011 Addenda, and 2013 Edition.	*http://go.asme.org/NRC.*
ASME OM Code, Division 1: 2009 Edition, 2011 Addenda, and 2012 Edition	*http://go.asme.org/NRC.*
ASME Standard NQA–1: 1983 Edition through 1994 Edition, 2008 Edition, and 2009–1a Addenda	*http://go.asme.org/NRC.*
ASME BPV Code Case N–729–4	*http://go.asme.org/NRC.*
ASME BPV Code Case N–770–2	*http://go.asme.org/NRC.*
ASME BPV Code Case N–824	*http://go.asme.org/NRC.*
ASME OM Code Case OMN–20	*http://go.asme.org/NRC.*

Throughout the development of this rulemaking, the NRC may post documents related to this rule, including public comments, on the Federal rulemaking Web site at *http://www.regulations.gov* under Docket ID NRC–2011–0088. The Federal rulemaking Web site allows you to receive alerts when changes or additions occur in a docket folder. To subscribe: (1) Navigate to the docket folder for NRC–2011–0088; (2) click the ''Sign up for Email Alerts'' link; and (3) enter your email address and select how frequently you would like to receive emails (daily, weekly, or monthly).

List of Subjects in 10 CFR Part 50

Administrative practice and procedure, Antitrust, Classified information, Criminal penalties, Education, Fire prevention, Fire protection, Incorporation by reference, Intergovernmental relations, Nuclear power plants and reactors, Penalties, Radiation protection, Reactor siting criteria, Reporting and recordkeeping requirements, Whistleblowing.

For the reasons set forth in the preamble, and under the authority of the Atomic Energy Act of 1954, as amended; the Energy Reorganization Act of 1974, as amended; and 5 U.S.C. 553, the NRC proposes to adopt the following amendments to 10 CFR part 50.

PART 50—DOMESTIC LICENSING OF PRODUCTION AND UTILIZATION FACILITIES

■ 1. The authority citation for part 50 continues to read as follows:

Authority: Atomic Energy Act of 1954, secs. 11, 101, 102, 103, 104, 105, 108, 122, 147, 149, 161, 181, 182, 183, 184, 185, 186, 187, 189, 223, 234 (42 U.S.C. 2014, 2131, 2132, 2133, 2134, 2135, 2138, 2152, 2167, 2169, 2201, 2231, 2232, 2233, 2234, 2235, 2236, 2237, 2239, 2273, 2282); Energy Reorganization Act of 1974, secs. 201, 202, 206, 211 (42 U.S.C. 5841, 5842, 5846, 5851); Nuclear Waste Policy Act of 1982, sec. 306 (42 U.S.C. 10226); National Environmental Policy Act of 1969 (42 U.S.C. 4332); 44 U.S.C. 3504 note; Sec. 109, Public Law 96–295, 94 Stat. 783.

■ 2. In § 50.55a:

■ a. Revise paragraphs (a) introductory text, (a)(1)(i) introductory text, (a)(1)(i)(E)(*12*), (a)(1)(i)(E)(*13*) and add paragraphs (a)(1)(i)(E)(*14*) through (a)(1)(i)(E)(*17*);

■ b. Revise paragraph (a)(1)(ii) introductory text, (a)(1)(ii)(C)(*48*) and (a)(1)(ii)(C)(*49*) and add paragraphs (a)(1)(ii)(C)(*50*) through (a)(1)(ii)(C)(*53*);

■ c. Revise paragraphs (a)(1)(iii)(B) and (a)(1)(iii)(C) and add paragraphs (a)(1)(iii)(D), (a)(1)(iii)(E);

■ d. Revise paragraphs (a)(1)(iv) introductory text and add paragraphs (a)(1)(iv)(B) and (a)(1)(iv)(C);

■ e. Add paragraph (a)(1)(v);

■ f. Revise paragraphs (b) introductory text, (b)(1) introductory text, (b)(1)(ii), (b)(1)(iv), and (b)(1)(vii) and add paragraph (b)(1)(viii);

■ g. Revise paragraphs (b)(2) introductory text, (b)(2)(vi);

■ h. Revise paragraph (b)(2)(viii) introductory text and add paragraphs (b)(2)(viii)(H) and (b)(2)(viii)(I);

■ i. Revise paragraphs (b)(2)(ix) introductory text, (b)(2)(ix)(D), (b)(2)(x), add paragraph (b)(2)(xviii)(D), revise paragraph (b)(2)(xxi)(A), and add paragraphs (b)(2)(xxx) through (b)(2)(xxxvii);

■ j. Revise paragraphs (b)(3) introductory text, (b)(3)(i), and (b)(3)(ii), add paragraph (b)(3)(iii), revise paragraphs (b)(3)(iv) introductory text and (b)(3)(iv)(A) though (b)(3)(iv)(D), and add paragraphs (b)(3)(vii) through (b)(3)(xi);

■ k. Revise paragraphs (b)(4) introductory text, (b)(5), and (b)(6);
■ l. Revise paragraphs (f) introductory text, (f)(2), (f)(3)(iii)(A), (f)(3)(iii)(B), (f)(3)(iv)(A), (f)(3)(iv)(B), (f)(4) introductory text, (f)(4)(i), (f)(4)(ii);
■ m. Revise paragraphs (g) introductory text, (g)(2), (g)(3) introductory text, (g)(3)(i), (g)(3)(ii), (g)(3)(v), (g)(4)(i), (g)(4)(ii), and (g)(6)(ii)(D)(*1*) through (g)(6)(ii)(D)(*4*), remove paragraphs (g)(6)(ii)(D)(*5*) and (g)(6)(ii)(D)(*6*), revise paragraphs (g)(6)(ii)(F)(*1*) through (g)(6)(ii)(F)(*10*), and add paragraphs (g)(6)(ii)(F)(*11*) through (g)(6)(ii)(F)(*13*).

The revisions and additions read as follows:

§ 50.55a Codes and standards.

(a) *Documents approved for incorporation by reference.* The standards listed in this paragraph have been approved for incorporation by reference by the Director of the Federal Register pursuant to 5 U.S.C. 552(a) and 1 CFR part 51. The standards are available for inspection, by appointment, at the NRC Technical Library, which is located at Two White Flint North, 11545 Rockville Pike, Rockville, Maryland 20852; telephone: 301–415–7000; email: *Library.Resource@nrc.gov;* or at 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/cfr/ibr-locations.html.*

(1) * * *

(i) *ASME Boiler and Pressure Vessel Code, Section III.* The editions and addenda for Section III of the ASME Boiler and Pressure Vessel Code (excluding Nonmandatory Appendices) are listed below, but limited by those provisions identified in paragraph (b)(1) of this section.

* * * * *

(E) * * *

(*12*) 2007 Edition,

(*13*) 2008 Addenda,

(*14*) 2009 Addenda,

(*15*) 2010 Edition,

(*16*) 2011 Addenda, and

(*17*) 2013 Edition.

(ii) *ASME Boiler and Pressure Vessel Code, Section XI.* The editions and addenda for Section XI of the ASME Boiler and Pressure Vessel Code (excluding Nonmandatory Appendix U) are listed below, but limited by those provisions identified in paragraph (b)(2) of this section.

* * * * *

(C) * * *

(*48*) 2007 Edition,

(*49*) 2008 Addenda,

(*50*) 2009 Addenda,

(*51*) 2010 Edition,

(*52*) 2011 Addenda, and

(*53*) 2013 Edition.

(iii) * * *

(B) *ASME BPV Code Case N–729–4.* ASME BPV Code Case N–729–4, ''Alternative Examination Requirements for PWR Reactor Vessel Upper Heads With Nozzles Having Pressure-Retaining Partial-Penetration Welds Section XI, Division 1'' (Approval Date: June 22, 2012), with the conditions in paragraph (g)(6)(ii)(D) of this section.

(C) *ASME BPV Code Case N–770–2.* ASME BPV Code Case N–770–2, ''Alternative Examination Requirements and Acceptance Standards for Class 1 PWR Piping and Vessel Nozzle Butt Welds Fabricated with UNS N06082 or UNS W86182 Weld Filler Material With or Without Application of Listed Mitigation Activities Section XI, Division 1'' (Approval Date: June 9, 2011), with the conditions in paragraph (g)(6)(ii)(F) of this section.

(D) *ASME BPV Code Case N–824.* ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1'' (Approval Date: October 16, 2012), with the conditions in paragraphs (b)(2)(xxxvii)(A) through (E) of this section.

(E) *ASME OM Code Case OMN–20.* ASME OM Code Case OMN–20, ''Inservice Test Frequency,'' in the 2012 Edition of the ASME OM Code. OMN–20 is referenced in paragraph (b)(3)(x).

(iv) *ASME Operation and Maintenance Code.* The editions and addenda for the ASME Operation and Maintenance of Nuclear Power Plants are listed below, but limited by those provisions identified in paragraph (b)(3) of this section.

* * * * *

(B) ''Operation and Maintenance of Nuclear Power Plants, Division 1: Section IST Rules for Inservice Testing of Light-Water Reactor Power Plants''

(*1*) 2009 Edition and

(*2*) 2011 Addenda.

(C) ''Operation and Maintenance of Nuclear Power Plants, Division 1: OM Code: Section IST.''

(*1*) 2012 Edition.

(*2*) [Reserved]

(v) *ASME Quality Assurance Requirements.*

(A) ASME NQA–1, ''Quality Assurance Program Requirements for Nuclear Facilities.''

(*1*) NQA–1–1983 Edition,

(*2*) NQA–1a–1983 Addenda,

(*3*) NQA–1b–1984 Addenda,

(*4*) NQA–1c–1985 Addenda,

(*5*) NQA–1–1986 Edition,

(*6*) NQA–1a–1986 Addenda,

(*7*) NQA–1b–1987 Addenda, and

(*8*) NQA–1c–1988 Addenda.

(*9*) NQA–1–1989 Edition,

(*10*) NQA–1a–1989 Addenda,

(*11*) NQA–1b–1991 Addenda, and

(*12*) NQA–1c–1992 Addenda.

(B) ASME NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications.''

(*1*) NQA–1–1994 Edition,

(*2*) NQA–1a–2008 Edition, and

(*3*) NQA–1a–2009 Addenda.

* * * * *

(b) *Use and conditions on the use of standards.* Systems and components of boiling and pressurized water-cooled nuclear power reactors must meet the requirements of the ASME Boiler and Pressure Vessel Code (BPV Code) and the ASME Operation and Maintenance of Nuclear Power Plants (OM Code) as specified in this paragraph. Each combined license for a utilization facility is subject to the following conditions.

(1) *Conditions on ASME BPV Code Section III.* Each manufacturing license, standard design approval, and design certification under part 52 of this chapter is subject to the following conditions. As used in this section, references to Section III refer to Section III of the ASME Boiler and Pressure Vessel Code and include the 1963 Edition through 1973 Winter Addenda and the 1974 Edition (Division 1) through the 2013 Edition (Division 1), subject to the following conditions:

* * * * *

(ii) *Section III condition: Weld leg dimensions.* When applying the 1989 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1) of this section, applicants and licensees may not apply the Section III provisions identified in Table 1 of this section for welds with leg size less than 1.09 t_n

TABLE 1 OF § 50.55A—PROHIBITED CODE PROVISIONS

Editions and Addenda	Code provision
1989 Addenda through 2013 Edition	Subparagraph NB–3683.4(c)(1). Subparagraph NB–3683.4(c)(2).
1989 Addenda through 2003 Addenda	Note 11 to Figure NC–3673.2(b)–1. Note 11 to Figure ND–3673.2(b)–1.
2004 Edition through 2010 Edition	Note 13 to Figure NC–3673.2(b)–1. Note 13 to Figure ND–3673.2(b)–1.
2011 Addenda through 2013 Edition	Note 11 to Table NC–3673.2(b)–1. Note 11 to Table ND–3673.2(b)–1.

* * * * *

(iv) *Section III condition: Quality assurance.* When applying editions and addenda later than the 1989 Edition of Section III, the requirements of NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications,'' 1983 Edition through the 1994 Edition, 2008 Edition, and the 2009–1a Addenda specified in either NCA–4000 or NCA–7000 of that edition and addenda of Section III may be used by an applicant or licensee provided that the administrative, quality, and technical provisions contained in that edition and addenda of Section III are used in conjunction with the applicant's or licensee's appendix B to 10 CFR part 50 quality assurance program; and that commitments contained in the applicant's or licensee's quality assurance program description which are either more stringent than those contained in NQA–1 or have no comparable provision in NQA–1 or Section III, govern the applicant's or licensee's Section III activities.

* * * * *

(vii) *Section III condition: Capacity certification and demonstration of function of incompressible-fluid pressure-relief valves.* When applying the 2006 Addenda through the 2013 Edition, applicants and licensees may use paragraph NB–7742, except that paragraph NB–7742(a)(2) may not be used. For a valve design of a single size to be certified over a range of set pressures, the demonstration of function tests under paragraph NB–7742 must be conducted as prescribed in NB–7732.2 on two valves covering the minimum set pressure for the design and the maximum set pressure that can be accommodated at the demonstration facility selected for the test.

(viii) *Section III condition: Use of ASME certification marks.* When applying editions and addenda earlier than the 2011 Addenda to the 2010 Edition, licensees may use either the ASME BPV Code Symbol Stamps or the ASME Certification Marks with the appropriate certification designators and class designators as specified in the 2013 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1) of this section.

(2) *Conditions on ASME BPV Code, Section XI.* As used in this section, references to Section XI refer to Section XI, Division 1, of the ASME Boiler and Pressure Vessel Code, and include the 1970 Edition through the 1976 Winter Addenda and the 1977 Edition through the 2013 Edition (excluding Nonmandatory Appendix U), subject to the following conditions:

* * * * *

(vi) *Section XI condition: Effective edition and addenda of Subsection IWE and Subsection IWL.* Licensees that implemented the expedited examination of containment, in accordance with Subsection IWE and Subsection IWL, during the period from September 9, 1996, to September 9, 2001, may use either the 1992 Edition with the 1992 Addenda or the 1995 Edition with the 1996 Addenda of Subsection IWE and Subsection IWL, as conditioned by the requirements in paragraphs (b)(2)(viii) and (ix) of this section, when implementing the initial 120-month inspection interval for the containment inservice inspection requirements of this section. Successive 120-month interval updates must be implemented in accordance with paragraph (g)(4)(ii) of this section.

* * * * *

(viii) *Section XI condition: Concrete containment examinations.* Applicants or licensees applying Subsection IWL, 1992 Edition with the 1992 Addenda, must apply paragraphs (b)(2)(viii)(A) through (E) of this section. Applicants or licensees applying Subsection IWL, 1995 Edition with the 1996 Addenda, must apply paragraphs (b)(2)(viii)(A), (b)(2)(viii)(D)(*3*), and (b)(2)(viii)(E) of this section. Applicants or licensees applying Subsection IWL, 1998 Edition through the 2000 Addenda, must apply paragraphs (b)(2)(viii)(E) and (F) of this section. Applicants or licensees applying Subsection IWL, 2001 Edition through the 2004 Edition, up to and including the 2006 Addenda, must apply paragraphs (b)(2)(viii)(E) through (G) of this section. Applicants or licensees applying Subsection IWL, 2007 Edition up to and including the 2008 Addenda must apply paragraph (b)(2)(viii)(E) of this section. Applicants or licensees applying Subsection IWL, 2007 Edition with the 2009 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must apply paragraph (b)(2)(viii)(H) and (b)(2)(viii)(I) of this section.

* * * * *

(H) *Concrete containment examinations: Eighth provision.* For each inaccessible area of concrete identified for evaluation under IWL–2512, the licensee must provide the applicable information specified in paragraphs (b)(2)(viii)(E)(1), (b)(2)(viii)(E)(2), and (b)(2)(viii)(E)(3) of this section in the ISI Summary Report required by IWA–6000.

(I) *Concrete containment examinations: Ninth provision.* During the period of extended operation of a renewed license under part 54 of this chapter, the licensee must perform the technical evaluation under IWL–2512(b) of inaccessible below-grade concrete surfaces exposed to foundation soil, backfill, or groundwater at periodic intervals not to exceed 5 years. In addition, the licensee must examine representative samples of the exposed portions of the below-grade concrete, when such below-grade concrete is excavated for any reason.

* * * * *

(ix) *Section XI condition: Metal containment examinations.* Applicants or licensees applying Subsection IWE, 1992 Edition with the 1992 Addenda, or the 1995 Edition with the 1996 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) through (E) of this section. Applicants or licensees applying Subsection IWE, 1998 Edition through the 2001 Edition with the 2003 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) and (B) and (b)(2)(ix)(F) through (I) of this section. Applicants or licensees applying Subsection IWE, 2004 Edition, up to and including the 2005 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A) and (B) and (b)(2)(ix)(F) through (H) of this section. Applicants or licensees applying Subsection IWE, 2004 Edition with the 2006 Addenda, must satisfy the requirements of paragraphs (b)(2)(ix)(A)(2) and (b)(2)(ix)(B) of this section. Applicants or licensees applying Subsection IWE, 2007 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, must satisfy the requirements of paragraphs (b)(2)(ix)(A)(2) and (b)(2)(ix)(B) and (J) of this section.

* * * * *

(D) *Metal containment examinations: Fourth provision.* This paragraph (b)(2)(ix)(D) may be used as an alternative to the requirements of IWE–2430. If the examinations reveal flaws or areas of degradation exceeding the acceptance standards of Table IWE–3410–1, an evaluation must be performed to determine whether additional component examinations are required. For each flaw or area of degradation identified that exceeds acceptance standards, the applicant or licensee must provide the following in the ISI Summary Report required by IWA–6000:

(*1*) A description of each flaw or area, including the extent of degradation, and the conditions that led to the degradation;

(*2*) The acceptability of each flaw or area and the need for additional examinations to verify that similar degradation does not exist in similar components;

(*3*) A description of necessary corrective actions; and

(*4*) The number and type of additional examinations to ensure detection of similar degradation in similar components.

* * * * *

(x) *Section XI condition: Quality assurance.* When applying the editions and addenda later than the 1989 Edition of ASME BPV Code, Section XI, the edition and addenda of NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications,'' 1983 Edition through the 1994 Edition, the 2008 Edition, and the 2009–1a Addenda specified in either IWA–1400 or Table IWA 1600–1 of that edition and addenda of Section XI, may be used by a licensee provided that the licensee uses its appendix B to 10 CFR part 50 quality assurance program in conjunction with Section XI requirements. Commitments contained in the licensee's quality assurance program description that are more stringent than those contained in NQA–1 must govern Section XI activities. Further, where NQA–1 and Section XI do not address the commitments contained in the licensee's appendix B quality assurance program description, the commitments must be applied to Section XI activities.

* * * * *

(xviii) * * *

(D) *NDE personnel certification: Fourth provision.* The use of Appendix VII and subarticle VIII–2200 of the 2011 Addenda and 2013 Edition of Section XI of the ASME BPV Code is prohibited. When using ASME BPV Code, Section XI editions and addenda later than the 2010 Edition, licensees and applicants must use the prerequisites for ultrasonic examination personnel certifications in Table VII–4110–1 and subarticle VIII–2200, Appendix VIII in the 2010 Edition.

* * * * *

(xxi) * * *

(A) *Table IWB–2500–1 examination requirements: First provision.* The provisions of Table IWB 2500–1, Examination Category B–D, Full Penetration Welded Nozzles in Vessels, Items B3.40 and B3.60 (Inspection Program A) and Items B3.120 and B3.140 (Inspection Program B) of the 1998 Edition must be applied when using the 1999 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section. A visual examination with magnification that has a resolution sensitivity to resolve 0.044 inch (1.1 mm) lower case characters without an ascender or descender (*e.g.,* a, e, n, v), utilizing the allowable flaw length criteria in Table IWB–3512–1, 1997 Addenda through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, with a limiting assumption on the flaw aspect ratio (*i.e.,* a/l = 0.5), may be performed instead of an ultrasonic examination.

* * * * *

(xxx) *Section XI condition: Steam generator preservice examinations.* Prior to plant start up with a newly installed steam generator, a 100 percent full length examination will be conducted of the tubing in each new steam generator instead of the preservice inspection requirements of IWB–2200(c).

(xxxi) *Section XI condition: Mechanical clamping devices.* The use of mechanical clamping devices on Class 1 piping and portions of piping systems that form the containment boundary is prohibited.

(xxxii) *Section XI condition: Summary report submittal.* When using ASME BPV Code, Section XI, 2010 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(ii) of this section, Summary Reports described in IWA–6000 must be submitted to the NRC. Preservice inspection summary reports shall be submitted prior to the date of placement of the unit into commercial service and inservice inspection summary reports shall be submitted within 90 calendar days of the completion of each refueling outage.

(xxxiii) *Section XI condition: Risk-Informed allowable pressure.* The use of Paragraph G–2216 in Appendix G in the 2011 Addenda and later editions and addenda of the ASME BPV Code, Section XI is prohibited.

(xxxiv) *Section XI condition: Disposition of flaws in Class 3 components.* When using the 2013 Edition of the ASME BPV Code, Section XI, to disposition flaws in Examination Category D–A components (*i.e.,* welded attachments for vessels, piping, pumps, and valves), the acceptance standards of IWD–3510 must be used.

(xxxv) *Section XI condition: Use of RT_{T0} in the K_{Ia} and K_{Ic} equations.* When using the 2013 Edition of the ASME BPV Code, Section XI, Appendix A, paragraph A–4200, if T_0 is available, then RT_{T0} may be used in place of RT_{NDT} for applications using the K_{Ic} equation and the associated K_{Ic} curve, but not for applications using the K_{Ia} equation and the associated K_{Ia} curve.

(xxxvi) *Section XI condition: Fracture toughness of irradiated materials.* When using the 2013 Edition of the ASME BPV Code, Section XI, Appendix A paragraph A–4400, the licensee shall obtain NRC approval before using irradiated T_0 and the associated RT_{T0} in establishing fracture toughness of irradiated materials.

(xxxvii) *Section XI condition: ASME BPV Code Case N–824.* Licensees may use the provisions of ASME BPV Code Case N–824, ''Ultrasonic Examination of Cast Austenitic Piping Welds From the Outside Surface Section XI, Division 1,'' subject to the following conditions.

(A) Ultrasonic examinations must be spatially encoded.

(B) Instead of Paragraph 1(c)(1)(–a) licensees shall use dual, transmit-receive, refracted longitudinal wave, multi-element phased array search units.

(C) Instead of Paragraph 1(c)(1)(–c)(–1), licensees shall use a phased array search unit with a center frequency between 500 kHz and 1 MHz.

(D) Instead of Paragraph 1(c)(1)(–c)(–2), licensees shall use a phased array search unit with a center frequency of 500 kHz.

(E) Instead of Paragraph 1(c)(1)(–d), the phased array search unit must produce angles from 30 to 70 degrees with a maximum increment of 5 degrees.

(3) *Conditions on ASME OM Code.* As used in this section, references to the OM Code are to the ASME OM Code, Subsections ISTA, ISTB, ISTC, ISTD, ISTE, and ISTF; Mandatory Appendices I, II, III, and V; and Nonmandatory Appendices A through H and J through M, in the 1995 Edition through the 2012 Edition as specified in paragraph (a)(1)(iv). The following conditions are applicable when implementing the ASME OM Code:

(i) *OM condition: Quality assurance.* When applying editions and addenda of the OM Code, the requirements of ASME Standard NQA–1, ''Quality Assurance Requirements for Nuclear Facility Applications,'' 1983 Edition through the 1994 Edition, 2008 Edition, and 2009–1a Addenda, are acceptable as permitted by either ISTA 1.4 of the 1995 Edition through 1997 Addenda or ISTA–1500 of the 1998 Edition through the latest edition and addenda of the OM Code incorporated by reference in paragraph (a)(1)(iv) of this section, provided the licensee uses its appendix B to 10 CFR part 50 quality assurance program in conjunction with the OM Code requirements. Commitments contained in the licensee's quality assurance program description that are more stringent than those contained in NQA–1 govern OM Code activities. If NQA–1 and the OM Code do not address the commitments contained in the licensee's appendix B quality assurance program description, the commitments must be applied to OM Code activities.

(ii) *OM condition: Motor-Operated Valve (MOV) testing.* Licensees must comply with the provisions for testing MOVs in OM Code, ISTC 4.2, 1995 Edition with the 1996 and 1997 Addenda, or ISTC–3500, 1998 Edition through the latest edition and addenda incorporated by reference in paragraph (a)(1)(iv) of this section, and must establish a program to ensure that MOVs continue to be capable of performing their design basis safety functions. Licensees implementing OM Code, Mandatory Appendix III, ''Preservice and Inservice Testing of Active Electric Motor Operated Valve Assemblies in Light-Water Reactor Power Plants,'' of the 2009 Edition, 2011 Addenda, and 2012 Edition shall comply with the following conditions:

(A) *MOV diagnostic test interval.* Licensees shall evaluate the adequacy of the diagnostic test interval for each MOV and adjust the interval as necessary, but not later than 5 years or three refueling outages (whichever is longer) from initial implementation of OM Code, Appendix III.

(B) *MOV testing impact on risk.* Licensees shall ensure that the potential increase in core damage frequency and large early release frequency associated with the extension is acceptably small when extending exercise test intervals for high risk MOVs beyond a quarterly frequency.

(C) *MOV risk categorization.* When applying Appendix III to the OM Code, licensees shall categorize MOVs according to their safety significance using the methodology described in ASME OM Code Case OMN–3, ''Requirements for Safety Significance Categorization of Components Using Risk Insights for Inservice Testing of LWR Power Plants,'' subject to the conditions applicable to OMN–3 which are set forth in Regulatory Guide 1.192, or using an MOV risk ranking methodology accepted by the NRC on a plant-specific or industry-wide basis in accordance with the conditions in the applicable safety evaluation.

(D) *MOV stroke time.* When applying Paragraph III–3600, ''MOV Exercising Requirements,'' of Appendix III to the OM Code, licensees shall verify that the stroke time of the MOV satisfies the assumptions in the plant safety analyses.

(iii) *OM condition: New Reactors.* In addition to complying with the provisions in the OM Code with the conditions specified in paragraph (b)(3) of this section, holders of operating licenses for nuclear power reactors that received construction permits under this part on or after the date 12 months after [the effective date of the final rule], and holders of combined licenses issued under 10 CFR part 52, whose initial fuel loading occurs on or after the date 12 months after [the effective date of the final rule] shall also comply with the following conditions, as applicable:

(A) *Power-operated valves.* Licensees shall periodically verify the capability of power-operated valves to perform their design-basis safety functions.

(B) *Check valves.* Licensees must perform bi-directional testing of check valves within the IST program where practicable.

(C) *Flow-induced vibration.* Licensees shall monitor flow-induced vibration from hydrodynamic loads and acoustic resonance during preservice testing and inservice testing to identify potential adverse flow effects on components within the scope of the IST program.

(D) *High risk non-safety systems.* Licensees shall assess the operational readiness of pumps, valves, and dynamic restraints within the scope of the Regulatory Treatment of Non-Safety Systems for applicable reactor designs.

(iv) *OM condition: Check valves (Appendix II).* Appendix II, ''Check Valve Condition Monitoring Program,'' of the OM Code, 2003 Addenda through the 2012 Edition, is acceptable for use without conditions with the clarifications that (1) the maximum test interval allowed by Appendix II for individual check valves in a group of two valves or more must be supported by periodic testing of a sample of check valves in the group during the allowed interval and (2) the periodic testing plan must be designed to test each valve of a group at approximate equal intervals not to exceed the maximum requirement interval. Licensees applying Appendix II of the OM Code, 1995 Edition with the 1996 and 1997 Addenda, shall satisfy the requirements of paragraphs (b)(3)(iv)(A) through (C) of this section. Licensees applying Appendix II, 1998 Edition through the 2012 Edition, shall satisfy the requirements of paragraphs (b)(3)(iv)(A), (B), and (D) of this section.

* * * * *

(vii) *OM condition: Subsection ISTB.* Subsection ISTB, 2011 Addenda, is prohibited for use.

(viii) *OM condition: Subsection ISTE.* Licensees may not implement the risk-informed approach for inservice testing (IST) of pumps and valves specified in Subsection ISTE, ''Risk-Informed Inservice Testing of Components in Light-Water Reactor Nuclear Power Plants,'' in the OM Code, 2009 Edition, 2011 Addenda, or 2012 Edition, without first obtaining NRC authorization to use Subsection ISTE as an alternative to the applicable IST requirements in the OM Code pursuant to § 50.55a(z).

(ix) *OM condition: Subsection ISTF.* Licensees applying Subsection ISTF, 2012 Edition, shall satisfy the requirements of Mandatory Appendix V, ''Pump Periodic Verification Test Program,'' of the ASME OM Code, 2012 Edition. Subsection ISTF, 2011 Addenda, is not acceptable for use.

(x) *OM condition: ASME OM Code Case OMN–20.* Licensees may implement ASME OM Code Case OMN–20, ''Inservice Test Frequency,'' which is incorporated by reference in paragraph (a)(1)(iii)(E) of this section.

(xi) *OM condition: Valve Position Indication.* When implementing ASME OM Code, Subsection ISTC–3700, ''Position Verification Testing,'' licensees shall develop and implement a method to verify that valve operation is accurately indicated by supplementing valve position indicating lights with other indications, such as flow meters or other suitable instrumentation, to provide assurance of proper obturator position.

(4) *Conditions on Design, Fabrication, and Materials Code Cases.* Each manufacturing license, standard design approval, and design certification application under part 52 of this chapter is subject to the following conditions. Licensees may apply the ASME BPV Code Cases listed in NRC Regulatory Guide 1.84, as incorporated by reference in paragraph (a)(3)(i) of this section, without prior NRC approval, subject to the following conditions:

* * * * *

(5) *Conditions on inservice inspection Code Cases.* Licensees may apply the ASME BPV Code Cases listed in NRC Regulatory Guide 1.147, as incorporate by reference in paragraph (a)(3)(ii) of this section, without prior NRC approval, subject to the following:

(i) *ISI Code Case condition: Applying Code Cases.* When a licensee initially applies a listed Code Case, the licensee must apply the most recent version of that Code Case incorporated by reference in paragraph (a) of this section.

(ii) *ISI Code Case condition: Applying different revisions of Code Cases.* If a licensee has previously applied a Code Case and a later version of the Code Case is incorporated by reference in paragraph (a) of this section, the licensee may continue to apply, to the end of the current 120-month interval, the previous version of the Code Case, as authorized, or may apply the later version of the Code Case, including any NRC-specified conditions placed on its use. Licensees who choose to continue use of the Code Case during subsequent 120-month ISI program intervals will be required to implement the latest version incorporated by reference into 10 CFR 50.55a as listed in Tables 1 and 2 of NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section.

(iii) *ISI Code Case condition: Applying annulled Code Cases.* Application of an annulled Code Case is prohibited unless a licensee previously applied the listed Code Case prior to it being listed as annulled in NRC Regulatory Guide 1.147. If a licensee has applied a listed Code Case that is later listed as annulled in NRC Regulatory Guide 1.147, the licensee may continue to apply the Code Case to the end of the current 120-month interval.

(6) *Conditions on Operation and Maintenance of Nuclear Power Plants Code Cases.* Licensees may apply the ASME Operation and Maintenance Code Cases listed in NRC Regulatory Guide 1.192, as incorporated by reference in paragraph (a)(3)(iii), without prior NRC approval, subject to the following:

(i) *OM Code Case condition: Applying Code Cases.* When a licensee initially applies a listed Code Case, the licensee must apply the most recent version of that Code Case incorporated by reference in paragraph (a) of this section.

(ii) *OM Code Case condition: Applying different revisions of Code Cases.* If a licensee has previously applied a Code Case and a later version of the Code Case is incorporated by reference in paragraph (a) of this section, the licensee may continue to apply, to the end of the current 120-month interval, the previous version of the Code Case, as authorized, or may apply the later version of the Code Case, including any NRC-specified conditions placed on its use. Licensees who choose to continue use of the Code Case during subsequent 120-month ISI program intervals will be required to implement the latest version incorporated by reference into 10 CFR 50.55a as listed in Tables 1 and 2 of NRC Regulatory Guide 1.192, as incorporated by reference in paragraph (a)(3)(iii) of this section.

(iii) *OM Code Case condition: Applying annulled Code Cases.* Application of an annulled Code Case is prohibited unless a licensee previously applied the listed Code Case prior to it being listed as annulled in NRC Regulatory Guide 1.192. If a licensee has applied a listed Code Case that is later listed as annulled in NRC Regulatory Guide 1.192, the licensee may continue to apply the Code Case to the end of the current 120-month interval.

* * * * *

(f) *Inservice testing requirements.* Systems and components of boiling and pressurized water-cooled nuclear power reactors must meet the requirements for preservice and inservice testing (referred to in this paragraph collectively as inservice testing) of the ASME BPV Code and ASME OM Code as specified in this paragraph. Each operating license for a boiling or pressurized water-cooled nuclear facility is subject to the following conditions. Each combined license for a boiling or pressurized water-cooled nuclear facility is subject to the following conditions, but the conditions in paragraphs (f)(4) through (6) of this section must be met only after the Commission makes the finding under § 52.103(g) of this chapter. Requirements for inservice inspection of Class 1, Class 2, Class 3, Class MC, and Class CC components (including their supports) are located in § 50.55a(g).

* * * * *

(2) *Design and accessibility requirements for performing inservice testing in plants with CPs issued between 1971 and 1974.* For a boiling or pressurized water-cooled nuclear power facility whose construction permit was issued on or after January 1, 1971, but before July 1, 1974, pumps and valves that are classified as ASME Code Class 1 and Class 2 must be designed and provided with access to enable the performance of inservice tests for operational readiness set forth in editions and addenda of Section XI of the ASME BPV incorporated by reference in paragraph (a)(1)(ii) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147 or NRC Regulatory Guide 1.192, as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section, respectively) in effect 6 months before the date of issuance of the construction permit. The pumps and valves may meet the inservice test requirements set forth in subsequent editions of this Code and addenda that are incorporated by reference in paragraph (a)(1)(ii) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147 or NRC Regulatory Guide 1.192, as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section, respectively), subject to the applicable conditions listed therein.

* * * * *

(3) * * *

(iii) * * *

(A) *Class 1 pumps and valves: First provision.* In facilities whose construction permit was issued before November 22, 1999, pumps and valves that are classified as ASME Code Class 1 must be designed and provided with access to enable the performance of inservice testing of those pumps and valves within the scope of the ASME OM Code for assessing operational readiness, as set forth in either the editions and addenda of Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1)(ii) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147 or NRC Regulatory Guide 1.192, as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section, respectively) which are applied to the construction of the particular pump or valve or the summer 1973 Addenda, whichever is later.

(B) *Class 1 pumps and valves: Second provision.* In facilities whose construction permit under this part, or design certification, design approval, combined license, or manufacturing license under part 52 of this chapter, issued on or after November 22, 1999, pumps and valves that are classified as ASME Code Class 1 must be designed and provided with access to enable the performance of inservice testing of those pumps and valves within the scope of the ASME OM Code for assessing operational readiness, as set forth in editions and addenda of the ASME OM Code (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.192, as incorporated by reference in paragraph (a)(3)(iii) of this section), incorporated by reference in paragraph (a)(1)(iv) of this section at the time the construction permit, combined license, manufacturing license, design certification, or design approval is issued.

(iv) * * *

(A) *Class 2 and 3 pumps and valves: First provision.* In facilities whose construction permit was issued before November 22, 1999, pumps and valves that are classified as ASME Code Class 2 and Class 3 that are within the scope of the ASME OM Code and are not covered by paragraph (f)(3)(iii)(A) of this section must be designed and be provided with access to enable the performance of inservice testing of the pumps and valves for assessing operational readiness set forth in the editions and addenda of Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1)(ii) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section) applied to the construction of the particular pump or valve or the Summer 1973 Addenda, whichever is later.

(B) *Class 2 and 3 pumps and valves: Second provision.* In facilities whose construction permit under this part, or design certification, design approval, combined license, or manufacturing license under part 52 of this chapter, issued on or after November 22, 1999, pumps and valves that are classified as ASME Code Class 2 and 3 that are within the scope of the ASME OM Code and are not covered by paragraph (f)(3)(iii)(B) of this section must be designed and provided with access to enable the performance of inservice testing of the pumps and valves for assessing operational readiness set forth in editions and addenda of the ASME OM Code (or the optional ASME OM Code Cases listed in NRC Regulatory Guide 1.192, as incorporated by reference in paragraph (a)(3)(iii) of this section), incorporated by reference in paragraph (a)(1)(iv) of this section at the time the construction permit, combined license, or design certification is issued.

* * * * *

(4) *Inservice testing standards requirement for operating plants.* Throughout the service life of a boiling or pressurized water-cooled nuclear power facility, pumps and valves that are within the scope of the ASME OM Code must meet the inservice test requirements (except design and access provisions) set forth in the ASME OM Code and addenda that become effective subsequent to editions and addenda specified in paragraphs (f)(2) and (3) of this section and that are incorporated by reference in paragraph (a)(1)(iv) of this section, to the extent practical within the limitations of design, geometry, and materials of construction of the components.

(i) *Applicable IST Code: Initial 120-month interval.* Inservice tests to verify operational readiness of pumps and valves, whose function is required for safety, conducted during the initial 120-month interval must comply with the requirements in the latest edition and addenda of the OM Code incorporated by reference in paragraph (a)(1)(iv) of this section on the date 12 months before the date of issuance of the operating license under this part, or 12 months before the date scheduled for initial loading of fuel under a combined license under part 52 of this chapter (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.192, as incorporated by reference in paragraph (a)(3)(iii) of this section, subject to the conditions listed in paragraph (b) of this section).

(ii) *Applicable IST Code: Successive 120-month intervals.* Inservice tests to verify operational readiness of pumps and valves, whose function is required for safety, conducted during successive 120-month intervals must comply with the requirements of the latest edition and addenda of the OM Code incorporated by reference in paragraph (a)(1)(iv) of this section 12 months before the start of the 120-month interval (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147 or NRC Regulatory Guide 1.192 as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section, respectively), subject to the conditions listed in paragraph (b) of this section.

* * * * *

(g) *Preservice and inservice inspection requirements.* Systems and components of boiling and pressurized water-cooled nuclear power reactors must meet the requirements of the ASME BPV Code as specified in this paragraph. Each operating license for a boiling or pressurized water-cooled nuclear facility is subject to the following conditions. Each combined license for a boiling or pressurized water-cooled nuclear facility is subject to the following conditions, but the conditions in paragraphs (g)(4) through (6) of this section must be met only after the Commission makes the finding under § 52.103(g) of this chapter. Requirements for inservice testing of Class 1, Class 2, and Class 3 pumps and valves are located in § 50.55a(f).

* * * * *

(2) *Accessibility requirements*—(i) *Accessibility requirements for plants with CPs issued between 1971 and 1974.* For a boiling or pressurized water-cooled nuclear power facility whose construction permit was issued on or after January 1, 1971, but before July 1, 1974, components that are classified as ASME Code Class 1 and Class 2 and supports for components that are classified as ASME Code Class 1 and Class 2 must be designed and be provided with the access necessary to perform the required preservice and inservice examinations set forth in editions and addenda of Section III or Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section) in effect 6 months before the date of issuance of the construction permit.

(ii) *Accessibility requirements for plants with CPs issued after 1974.* For a boiling or pressurized water-cooled nuclear power facility, whose construction permit under this part, or design certification, design approval, combined license, or manufacturing license under part 52 of this chapter, was issued on or after July 1, 1974, components that are classified as ASME Code Class 1, Class 2, and Class 3 and supports for components that are classified as ASME Code Class 1, Class 2, and Class 3 must be designed and provided with the access necessary to perform the required preservice and inservice examinations set forth in editions and addenda of Section III or Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section) applied to the construction of the particular component.

(iii) *Accessibility requirements: Meeting later Code requirements.* All components (including supports) may meet the requirements set forth in subsequent editions of codes and addenda or portions thereof that are incorporated by reference in paragraph (a) of this section, subject to the conditions listed therein.

(3) *Preservice examination requirements*—(i) *Preservice examination requirements for plants with CPs issued between 1971 and 1974.* For a boiling or pressurized water-cooled nuclear power facility whose construction permit was issued on or after January 1, 1971, but before July 1, 1974, components that are classified as ASME Code Class 1 and Class 2 and supports for components that are classified as ASME Code Class 1 and Class 2 must meet the preservice examination requirements set forth in editions and addenda of Section III or Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section) in effect 6 months before the date of issuance of the construction permit.

(ii) *Preservice examination requirements for plants with CPs issued after 1974.* For a boiling or pressurized water-cooled nuclear power facility, whose construction permit under this part, or design certification, design approval, combined license, or manufacturing license under part 52 of this chapter, was issued on or after July 1, 1974, components that are classified as ASME Code Class 1, Class 2, and Class 3 and supports for components that are classified as ASME Code Class 1, Class 2, and Class 3 must meet the preservice examination requirements set forth in the editions and addenda of Section III or Section XI of the ASME BPV Code incorporated by reference in paragraph (a)(1) of this section (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section) applied to the construction of the particular component.

* * * * *

(v) *Preservice examination requirements: Meeting later Code requirements.* All components (including supports) may meet the requirements set forth in subsequent editions of codes and addenda or portions thereof that are incorporated by reference in paragraph (a) of this section, subject to the conditions listed therein.

* * * * *

(4) * * *

(i) *Applicable ISI Code: Initial 120-month interval.* Inservice examination of components and system pressure tests conducted during the initial 120-month inspection interval must comply with the requirements in the latest edition and addenda of the Code incorporated by reference in paragraph (a) of this section on the date 12 months before the date of issuance of the operating license under this part, or 12 months before the date scheduled for initial loading of fuel under a combined license under part 52 of this chapter (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, when using Section XI, or NRC Regulatory Guide 1.192, when using the OM Code, as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section, respectively), subject to the conditions listed in paragraph (b) of this section.

(ii) *Applicable ISI Code: Successive 120-month intervals.* Inservice examination of components and system pressure tests conducted during successive 120-month inspection intervals must comply with the requirements of the latest edition and addenda of the Code incorporated by reference in paragraph (a) of this section 12 months before the start of the 120-month inspection interval (or the optional ASME Code Cases listed in NRC Regulatory Guide 1.147, when using Section XI, or NRC Regulatory Guide 1.192, when using the OM Code, as incorporated by reference in paragraphs (a)(3)(ii) and (iii) of this section), subject to the conditions listed in paragraph (b) of this section. However, a licensee whose inservice inspection interval commences during the 12 through 18-month period after July 21, 2011, may delay the update of their Appendix VIII program by up to 18 months after July 21, 2011.

* * * * *

(6) * * *

(ii) * * *

(D) * * *

(*1*) *Implementation:* Holders of operating licenses or combined licenses for pressurized-water reactors as of or after [the effective date of the final rule] shall implement the requirements of ASME BPV Code Case N–729–4 instead of ASME BPV Code Case N–729–1, subject to the conditions specified in paragraphs (g)(6)(ii)(D)(*2*) through (*4*) of this section, by the first refueling outage starting after [the effective date of the final rule].

(*2*) *Appendix I use:* Appendix I of ASME BPV Code Case N–729–4 shall not be implemented without prior NRC approval.

(*3*) *Bare metal visual frequency:* Instead of Note 4 of ASME BPV Code Case N–729–4, the following shall be implemented; If EDY<8 and if no flaws are found that are attributed to PWSCC; (a) A bare metal visual examination is not required during refueling outages when a volumetric or surface examination is performed, (b) If a wetted surface examination has been performed of all of the partial penetration welds during the previous non-visual examination, the reexamination frequency may be extended to every third refueling outage or 5 calendar years, whichever is less, provided an IWA–2212 VT–2 visual examination of the head is performed under the insulation through multiple access points in outages that the VE is not completed. This IWA–2212 VT–2 visual examination may be performed with the reactor vessel depressurized.

(*4*) *Surface exam acceptance criteria:* In addition to the requirements of paragraph-3132.1(b) of ASME BPV Code Case N–729–4, a component whose surface examination detects rounded indications greater than allowed in Paragraph NB–5352 in size on the partial-penetration or associated fillet weld shall be classified as having an unacceptable indication and corrected in accordance with the provisions of paragraph-3132.2 of ASME BPV Code Case N–729–4.

* * * * *

(F) * * *

(*1*) *Implementation:* Holders of operating licenses or combined licenses for pressurized-water reactors as of or after [the effective date of the final rule] shall implement the requirements of ASME BPV Code Case N–770–2 instead of ASME BPV Code Case N–770–1, subject to the conditions specified in paragraphs (g)(6)(ii)(F)(*2*) through (*13*) of this section, by the first refueling outage starting after [the effective date of the final rule].

(*2*) *Categorization:* Full structural weld overlays, authorized by the NRC staff in accordance with the alternatives approval process of this section, may be categorized as Inspection Items C–1 or F–1, as appropriate. Welds that have been mitigated by the Mechanical Stress Improvement Process (MSIP™) may be categorized as Inspection Items D or E, as appropriate, provided the criteria in Appendix I of the code case have been met. For the purpose of determining ISI frequencies, all other butt welds that rely on Alloy 82/182 for structural integrity shall be categorized as Inspection Items A–1, A–2, or B until the NRC staff has reviewed the mitigation and authorized an alternative code case Inspection Item for the mitigated weld, or an alternative code case Inspection Item is used based on conformance with an ASME mitigation code case endorsed in NRC Regulatory Guide 1.147 with any applying conditions specified in NRC Regulatory Guide 1.147, as incorporated by reference in paragraph (a)(3)(ii) of this section. Paragraph-1100(e) of ASME BPV Code Case N–770–2 shall not be used to exempt welds that rely on Alloy 82/182 for structural integrity from any requirement of paragraph (g)(6)(ii)(F) of this section.

(*3*) *Baseline examinations:* Baseline examinations for welds in Table 1 of ASME BPV Code Case N–770–2, Inspection Items A–1, A–2, and B, if not previously performed or currently scheduled to be performed in an ongoing refueling outage at the time this rule becomes effective, in accordance with paragraph (g)(6)(ii)(F) of this section, shall be completed by the end of the next refueling outage. Previous examinations of these welds can be credited for baseline examinations only if they were performed within the re-inspection period for the weld item in Table 1 of ASME BPV Code Case N–770–2 and the examination of each weld meets the examination requirements of paragraphs -2500(a) or -2500(b) of ASME BPV Code Case N–770–2. Other previous examinations that do not meet these requirements can be used to meet the baseline examination requirement, provided NRC approval in accordance with paragraphs (z)(1) or (2) of this section, is granted prior to the end of the next refueling outage.

(*4*) *Examination coverage:* When implementing paragraph-2500(a) of ASME Code Case N–770–2, essentially 100 percent volumetric examination coverage shall be obtained, including greater than 90 percent volumetric examination coverage for circumferential flaws. Licensees are prohibited from using Paragraph-2500(c) and -2500(d) of ASME BPV Code Case N–770–2 to meet examination requirements.

(*5*) *Inlay/onlay inspection frequency:* All hot-leg operating temperature welds in Inspection Items G, H, J, and K shall be inspected each inspection interval. A 25 percent sample of Inspection Items G, H, J, and K cold-leg operating temperature welds shall be inspected whenever the core barrel is removed (unless it has already been inspected within the past 10 years) or within 20 years, whichever is less.

(*6*) *Reporting requirements:* For any mitigated weld whose volumetric examination detects growth of existing flaws in the required examination volume that exceed the previous IWB–3600 flaw evaluations or new flaws, a report summarizing the evaluation, along with inputs, methodologies, assumptions, and causes of the new flaw or flaw growth is to be provided to the NRC prior to the weld being placed in service other than modes 5 or 6.

(*7*) *Defining ''t'':* For Inspection Items G, H, J, and K, when applying the acceptance standards of ASME BPV Code, Section XI, IWB–3514, for planar flaws contained within the inlay or onlay, the thickness ''t'' in IWB–3514 is the thickness of the inlay or onlay. For planar flaws in the balance of the dissimilar metal weld examination volume, the thickness ''t'' in IWB–3514 is the combined thickness of the inlay or onlay and the dissimilar metal weld.

(*8*) *Optimized weld overlay examination:* Initial inservice examination of Inspection Item C–2 welds, shall be performed between the third refueling outage and no later than 10 years after application of the overlay.

(*9*) *Deferral:* Note (11)(b)(1) in ASME BPV Code Case N–770–2 shall not be used to defer the initial inservice examination of optimized weld overlays (*i.e.,* Inspection Item C–2 of ASME BPV Code Case N–770–2).

(*10*) *Examination technique:* Note 14(b) of Table 1 and Note (b) of Figure 5(a) of ASME BPV Code Case N–770–2 may only be implemented if the requirements of Note 14(a) of Table 1 of ASME BPV Code Case N–770–2 cannot be met.

(*11*) *Cast stainless steel:* Examination of ASME Code Class 1 piping and vessel nozzle butt welds involving cast stainless steel materials, shall be performed with Appendix VIII, Supplement 9 qualifications, or qualifications similar to Appendix VIII, Supplement 2 or 10 using cast stainless steel mockups no later than the next scheduled weld examination after January 1, 2020, in accordance with the requirements of paragraph-2500(a).

(*12*) *Stress improvement inspection coverage:* Under Paragraph I.5.1, for cast stainless steel items, the required examination volume shall be examined by Appendix VIII procedures to the maximum extent practical including 100 percent of the susceptible material volume.

(*13*) *Encoded ultrasonic examination:* Ultrasonic examinations performed in accordance with the requirements of Table 1 for Inspection Item A–1, A–2, B, E, F–2, J, and K shall be performed for essentially 100 percent of the inspection surface area using an encoded method.

* * * * *

Dated at Rockville, Maryland, this 21st day of August 2015.

For the Nuclear Regulatory Commission.

Michele G. Evans,

Acting Director, Office of Nuclear Reactor Regulation.

[FR Doc. 2015–23193 Filed 9–17–15; 8:45 am]

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Part VI

Department of the Treasury

Internal Revenue Service

26 CFR Part 1

Dividend Equivalents From Sources Within the United States; Final Rule

DEPARTMENT OF THE TREASURY

Internal Revenue Service

26 CFR Part 1

[TD 9734]

RIN 1545–BJ56

Dividend Equivalents From Sources Within the United States

AGENCY: Internal Revenue Service (IRS), Treasury.

ACTION: Final regulations and temporary regulations.

SUMMARY: This document provides guidance to nonresident alien individuals and foreign corporations that hold certain financial products providing for payments that are contingent upon or determined by reference to U.S. source dividend payments. This document also provides guidance to withholding agents that are responsible for withholding U.S. tax with respect to a dividend equivalent.

DATES: *Effective Date:* These regulations are effective on September 18, 2015.

Applicability Dates: For dates of applicability, see §§ 1.871–14(j)(3), 1.871–15(r), 1.871–15T(r)(4), 1.1441–1(f)(4), 1.1441–1T(f)(3), 1.1441–2(f), 1.1441–3(h)(3), 1.1441–7(a)(4), and 1.1473–1(f).

FOR FURTHER INFORMATION CONTACT: D. Peter Merkel or Karen Walny at (202) 317–6938 (not a toll-free number).

SUPPLEMENTARY INFORMATION:

Paperwork Reduction Act

The collection of information contained in these final regulations has been reviewed and approved by the Office of Management and Budget in accordance with the Paperwork Reduction Act of 1995 (44 U.S.C. 3507(d)) under control numbers 1545–0096 and 1545–1597. The collections of information in this final regulation are in § 1.871–15(p), and are an increase in the total annual burden in the current regulations under §§ 1.1441–1 through 1.1441–9, 1.1461–1, and 1.1474–1. This information is required to establish whether a payment is treated as a U.S. source dividend for purposes of section 871(m). This information will be used for audit and examination purposes. The IRS intends that these information collection requirements will be satisfied by persons complying with revised chapter 3 reporting requirements and the requirements of the applicable QI revenue procedure to be revised by the IRS, or alternative certification and documentation requirements set out in these regulations. An agency may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a valid control number.

Books or records relating to a collection of information must be retained as long as their contents may become material in the administration of any internal revenue law. Generally, tax returns and return information are confidential, as required by 26 U.S.C. 6103.

Background

On January 23, 2012, the **Federal Register** published temporary regulations (TD 9572) at 77 FR 3108 (2012 temporary regulations), and a notice of proposed rulemaking by cross-reference to the temporary regulations and notice of public hearing at 77 FR 3202 (2012 proposed regulations, and together with the 2012 temporary regulations, 2012 section 871(m) regulations) under section 871(m) of the Internal Revenue Code (Code). The 2012 section 871(m) regulations relate to dividend equivalents from sources within the United States paid to nonresident alien individuals and foreign corporations. Corrections to the 2012 temporary regulations were published on February 6, 2012, and March 8, 2012, in the **Federal Register** at 77 FR 5700 and 77 FR 13969, respectively. A correcting amendment to the 2012 temporary regulations was also published on August 31, 2012, in the **Federal Register** at 77 FR 53141. The Treasury Department and the IRS received written comments on the 2012 proposed regulations, and a public hearing was held on April 27, 2012.

On December 5, 2013, the **Federal Register** published final regulations and removal of temporary regulations (TD 9648) at 78 FR 73079 (2013 final regulations), which finalized a portion of the 2012 section 871(m) regulations. Also on December 5, 2013, the **Federal Register** published a withdrawal of notice of proposed rulemaking, a notice of proposed rulemaking, and a notice of public hearing at 78 FR 73128 (2013 proposed regulations). In light of comments on the 2012 proposed regulations, the 2013 proposed regulations described a new approach for determining whether a payment made pursuant to a notional principal contract (NPC) or an equity-linked instrument (ELI) is a dividend equivalent based on the delta of the contract. In response to written comments on the 2013 proposed regulations, the Treasury Department and the IRS released Notice 2014–14, 2014–13 IRB 881, on March 24, 2014 (see § 601.601(d)(2)(ii)(*b*)), stating that the Treasury Department and the IRS anticipated limiting the application of the rules with respect to specified ELIs described in the 2013 proposed regulations to ELIs issued on or after 90 days after the date of publication of final regulations.

The Treasury Department and the IRS received written comments on the 2013 proposed regulations, which are available at *www.regulations.gov*. The public hearing scheduled for April 11, 2013, was cancelled because no request to speak was received. This Treasury decision generally adopts the 2013 proposed regulations with the changes discussed in this preamble. This Treasury decision also includes temporary regulations, which provide new rules for determining whether certain complex derivatives are subject to section 871(m) and for payments to certain dealers in response to comments on the 2013 proposed regulations.

Summary of Comments and Explanation of Provisions

I. In General

The Treasury Department and the IRS received numerous comments regarding the 2013 proposed regulations. Most comments agreed that the approach taken in the 2013 proposed regulations, in particular the use of a test based on delta, was a fair and practical way to apply section 871(m) to financial instruments linked to one or more U.S. equity securities. Commenters, however, identified a number of issues with the 2013 proposed regulations. Many of the comments suggested modifications and clarifications to the 2013 proposed regulations before they are issued as final regulations. Those comments are summarized in Part II of this preamble. Part II also explains the changes made to the final regulations in response to those comments.

Several of the issues identified by commenters required more significant changes or additions to the 2013 proposed regulations. To allow taxpayers adequate opportunity to consider and comment on these changes, the Treasury Department and the IRS are issuing portions of the regulations as temporary and proposed regulations. Those provisions, and the relevant comments, are summarized in Part III of this preamble.

II. Final Regulations

A. Source of a Dividend Equivalent

The 2013 proposed regulations provide that a dividend equivalent is treated as a dividend from sources within the United States for purposes of sections 871(a), 881, 892, 894, and

4948(a), and chapters 3 and 4 of subtitle A of the Code. This rule follows section 871(m)(1) but adds the reference to section 894 to clarify (as provided in § 1.894–1(c)(2)) that a dividend equivalent is treated as a dividend for purposes of any provision regarding dividends in an income tax treaty. The final regulations retain the general sourcing provision. *See* § 1.871–15(b).

B. Definition of a Dividend Equivalent

The 2013 proposed regulations define a dividend equivalent as (1) any substitute dividend that references a U.S. source dividend made pursuant to a securities lending or sale-repurchase transaction, (2) any payment that references a U.S. source dividend made pursuant to a specified NPC, (3) any payment that references a U.S. source dividend made pursuant to a specified ELI, or (4) any other substantially similar payment. A payment references a U.S. source dividend if the payment is directly or indirectly contingent upon a U.S. source dividend or determined by reference to such a dividend. While the transactions described in (1) and (2) are transactions described in sections 871(m)(2)(A) and (B), respectively, the 2013 proposed regulations extend section 871(m) to the transactions described in (3) and (4) under the regulatory authority granted in section 871(m)(2)(C), which includes as a dividend equivalent ''any other payment determined by the Secretary to be substantially similar to a payment described in subparagraph (A) or (B)'' of section 871(m)(2). The final regulations retain this four-part definition of a dividend equivalent. *See* § 1.871–15(c)(1). The final regulations also provide certain exceptions to the term ''dividend equivalent,'' which are described in section II.D of this preamble.

Section 871(m)(3)(A) provides a temporary definition of the term ''specified notional principal contract.'' This definition is effective for payments made on or after September 14, 2010, and on or before March 18, 2012. Section 871(m)(3)(B) provides that, for payments made after March 18, 2012, a specified NPC includes ''any notional principal contract unless the Secretary determines that such contract is of a type which does not have the potential for tax avoidance.'' The 2013 final regulations extend the applicability of the temporary statutory definition in section 871(m)(3)(A) (the four-part definition provided in paragraphs (3)(A)(i) through (iv)) to payments made before January 1, 2016. These final regulations amend the 2013 final regulations to extend the application of the temporary statutory definition adopted in the 2013 final regulations to payments made before January 1, 2017.

Pursuant to the grant of authority in section 871(m)(2)(C), the 2013 proposed regulations provide that certain payments made pursuant to a specified ELI are substantially similar to a dividend equivalent payment. Section 1.871–15(c)(1)(iii) of the 2013 proposed regulations defines a dividend equivalent to include any payment that references the payment of a dividend from an underlying security on a specified ELI. Section 1.871–15(a)(3) of the 2013 proposed regulations defines an ELI (whether or not specified) as any financial transaction (other than a securities lending or sale-repurchase transaction or an NPC) that references the value of one or more underlying securities. Forward contracts, futures contracts, options, debt instruments convertible into underlying securities, and debt instruments that have payments linked to underlying securities are common examples of an ELI.

C. The Delta Test

The 2012 proposed regulations used a multi-factor test to determine whether an NPC or ELI is a specified contract subject to withholding under section 871(m). The 2013 proposed regulations replace the multi-factor test with a single-factor test that employs a ''delta'' threshold to determine whether a transaction is a section 871(m) transaction. Delta refers to the ratio of a change in the fair market value of a contract to a small change in the fair market value of the property referenced by the contract. Delta is widely used by participants in the derivatives markets to measure and manage risk. Under the test in the 2013 proposed regulations, any NPC or ELI that had a delta of 0.70 or greater when the long party acquired the transaction would be a section 871(m) transaction subject to withholding.

The Treasury Department and the IRS proposed a delta-based standard after concluding that it would provide a comparatively simple, administrable, and objective framework that would also minimize potential avoidance of U.S. withholding tax. A financial instrument that provides an economic return that is substantially similar to the return on the underlying stock should be taxed in the same manner as the underlying stock for the purpose of section 871(m). The Treasury Department and the IRS concluded that the delta test was the best way to identify these instruments.

The Treasury Department and the IRS received many comments regarding the delta test. Commenters generally agreed that the delta test was both a fair and comprehensive way to implement section 871(m), but provided comments on several aspects of the test. The major concerns noted in the comments relate to: (1) The use of 0.70 as the delta threshold; (2) the time for testing delta; (3) the ability of parties to the transaction to obtain and track the necessary delta information; and (4) the difficulty of determining an initial delta with respect to certain complex equity derivatives (in contrast with simple contracts, as defined in Part II.C.4 of this preamble).

1. Delta Threshold

Comments on the 2013 proposed regulations recommended raising the delta threshold, with suggestions ranging from a delta of 0.80 to 0.95. The majority of comments preferred a delta threshold of 0.90 or greater. Comments maintained that a higher delta would more accurately capture transactions that are economically equivalent to stock ownership and likely to be used for tax-avoidance. One comment noted that a 0.80 delta standard, although not prescribed in regulatory guidance, is used by some practitioners as a yardstick to judge economic equivalence in other tax contexts.

The Treasury Department and the IRS agree that the 0.70 delta in the 2013 proposed regulations could apply to contracts with economic characteristics that do not sufficiently resemble the underlying security to be within the scope of section 871(m). On the other hand, a delta threshold that is 0.90 (or higher) would exclude many instruments that are surrogates for the underlying security, such as deep-in-the-money options. The final regulations adopt a delta threshold of 0.80, which strikes a balance between the potential over-inclusiveness of the 0.70 delta threshold and the likelihood that a 0.90 (or higher) threshold would exclude transactions with economic returns that closely resemble an underlying security.

Several comments noted that a delta ratio is intended to measure the sensitivity of the value of a contract to comparatively small changes in the market value of the referenced property and suggested that the regulations incorporate this qualification in the definition of delta. The final regulations accept this suggestion and clarify the definition of delta by specifying that delta is calculated with respect to a small change in the fair market value of the property referenced by the contract.

Typically, a small change is a change of less than 1 percent.

2. Time for Testing Delta

Many comments stated that the requirement to test delta each time a contract is acquired would be extremely difficult to administer, especially for ELIs that trade frequently. Multiple testing events create the possibility that identical instruments acquired at different times would have different tax characteristics, which withholding systems are generally not designed to handle. To ease compliance, comments suggested that delta be tested only when a contract is issued. For derivatives that are listed and cleared through central clearinghouses, another comment suggested that the delta test would be more administrable if taxpayers were permitted to simplify their calculations. For example, delta could be calculated using the fair market value of an ELI determined as of the market close on the trading day prior to the date the ELI is acquired, even though this approach would result in a less accurate calculation. Other comments suggested that, in determining the delta of an option, only the stock price at the time the option is entered into should be considered.

The Treasury Department and the IRS are persuaded that the difficulties of testing delta each time an NPC or ELI is acquired outweigh the benefit of the increased accuracy of that approach. Accordingly, the final regulations provide that the delta of an ELI or NPC is determined only when the instrument is issued; it is not re-tested when the instrument is purchased or otherwise acquired in the secondary market. Consequently, only an NPC or ELI that has a delta of 0.80 or greater at the time it is issued is a specified NPC or specified ELI.

For purposes of § 1.871–15, an instrument is treated as ''issued'' when it is entered into, purchased, or otherwise acquired at its inception or original issuance, which includes an issuance that results from a deemed exchange pursuant to section 1001. The requirement to test delta only at the time an instrument is issued also extends to the rules for determining the amount of each dividend equivalent (as discussed in section E.1 of this preamble).

3. Access to Delta Information

Comments noted practical issues with obtaining delta information, particularly for exchange-traded positions where the dealer is not involved in determining pricing and the short party may not have the expertise to calculate delta. Comments suggested adopting an alternative test for identifying high-delta options based on their relative intrinsic value (amount by which the option is in-the-money) and relative extrinsic value (time value). This test would require the simpler calculation of determining the applicable strike price as a percentage of the current fair market value of the ELI and deeming ELIs at a certain percentage as passing or failing the delta threshold. Alternatively, comments suggested permitting the long party to rely on commonly available online tools to calculate delta for exchange-traded ELIs, provided that the taxpayer uses inputs that are within the range of commercially acceptable variation, uses a consistent methodology, and records its calculations contemporaneously. Comments also recommended relying on an anti-abuse rule for particularly complex derivatives for which delta information would be unavailable to any party other than the issuer, speculating that the increased cost and risk of complex transactions generally would outweigh any tax savings.

The Treasury Department and the IRS are concerned that these alternative tests or shorthand methods for determining delta may result in uncertainty for withholding agents and the IRS that could make it difficult to determine the status of potential section 871(m) transactions. Moreover, the changes to the final regulations to require that delta be tested only when a contract is first issued, accompanied by enhanced reporting rules (described in more detail later in this preamble), make these alternative tests unnecessary. Accordingly, the final regulations do not adopt these recommendations.

However, in order to simplify the delta calculation for contracts that reference multiple underlying securities, the final regulations provide that a short party may calculate delta using a single exchange-traded security in certain circumstances. More specifically, if a short party issues a contract that references a basket of 10 or more underlying securities and uses an exchange-traded security, such as an exchange-traded fund, that references substantially the same underlying securities to hedge the contract at the time it is issued, the short party may use the hedge security to determine the delta of the security it is issuing rather than determining the delta of each security referenced in the basket.

4. Contracts With Indeterminate Deltas

Although commenters generally agreed that the delta test was fair and practical for the majority of equity-linked derivatives, numerous comments explained that the delta test would be difficult or impossible to apply to certain more exotic equity derivatives. For example, contracts that have asymmetrical or binary payouts may reference a different number of shares of an underlying security at different payout points. Similarly, contracts that have path-dependent payouts may reference multiple underlying securities, with payouts that are interdependent on the performance of each underlying security. In each of these cases, comments noted that the delta is indeterminate because the number of shares of the underlying security that determine the payout of the derivative cannot be known at the time the contract is entered into.

The Treasury Department and the IRS agree that an alternative to the delta test is needed for contracts with indeterminate deltas. To address these contracts, the final regulations distinguish between simple contracts and complex contracts.

Generally, a simple contract is a contract that references a single, fixed number of shares of one or more issuers to determine the payout. The number of shares must be known when the contract is issued. In addition, the contract must have a single maturity or exercise date on which all amounts (other than any upfront payment or any periodic payments) are required to be calculated with respect to the underlying security. The fact that a contract has more than one expiry, or a continuous expiry, does not preclude the contract from being a simple contract. Thus, an American-style option is a simple contract even though the option may be exercised by the holder at any time on or before the expiration of the option if amounts due under the contract are determined by reference to a single, fixed number of shares on the exercise date. Most NPCs and ELIs are expected to be simple contracts and remain subject to the delta test described above.

A complex contract is any contract that is not a simple contract. Contracts with indeterminate deltas are classified as complex contracts, which are subject to a new substantial equivalence test. That test is included in the temporary regulations, described in more detail in Part III of this preamble. The delta test in the final regulations therefore applies only to simple contracts.

D. Exceptions for Certain Payments and Transactions

Several comments requested that the final regulations exclude certain payments from the definition of ''dividend equivalent'' or exclude certain transactions from the definition of ''section 871(m) transaction.'' These comments generally noted that the payment or transaction at issue either is already taxed under another provision of the Code or does not provide the long party with an opportunity to avoid gross basis taxation on U.S. source dividends.

1. Payment Referencing Distributions That Are Not Dividends

The 2013 proposed regulations provide that a payment referencing a distribution on an underlying security is not a dividend equivalent to the extent that the distribution would not be subject to tax pursuant to section 871 or section 881 if the long party owned the underlying security directly. The final regulations retain this provision. *See* § 1.871–15(c)(2)(i).

2. Section 305 Coordination

Under sections 305(b) and (c) and regulations authorized by section 305(c), a change to the conversion ratio or conversion price of a convertible debt instrument that is a convertible security for purposes of section 305 (a convertible security) may be treated as a distribution of property to which section 301 applies made to the holder of the convertible security. *See* § 1.305–7. To the extent such a distribution is treated under section 301(c)(1) as a dividend as defined in section 316 (a section 305 dividend), § 1.1441–2(d)(1) would require withholding on the section 305 dividend without regard to the fact that there is no payment at that time. Absent special rules, a section 305 dividend resulting from a change in conversion ratio or price of a convertible security that is a section 871(m) transaction could also be subject to withholding as a dividend equivalent.

The 2013 proposed regulations provide that a payment pursuant to a section 871(m) transaction is not a dividend equivalent to the extent that it is treated as a distribution taxable as a dividend pursuant to section 305. Comments noted that section 305 dividends and dividend equivalents under section 871(m) arise in different contexts and are determined differently. Moreover, section 305 dividends will reduce earnings and profits pursuant to section 312. Comments suggested that the regulations provide more detail to coordinate these two provisions, including guidance on how to reconcile withholding on the delta-based dividend equivalent in these regulations with withholding otherwise required on section 305 dividends.

After consideration of the comments, these final regulations clarify that a dividend equivalent with respect to a section 871(m) transaction is reduced by any amount treated in accordance with section 305(b) and (c) as a dividend with respect to the underlying security referenced by the section 871(m) transaction. For example, if a change in the conversion ratio of a convertible security that is a section 871(m) transaction is treated as a section 305 dividend made to the holder of the convertible security, a dividend equivalent is reduced by the amount of the section 305 dividend arising from such change.

Although a transaction (for example, a change in conversion ratio of a convertible security) may give rise to both a dividend equivalent and a section 305 dividend, dividend equivalents and section 305 dividends have different characteristics. These final regulations do not alter any of the rules applicable to section 305 dividends. As noted in Part II.L. of this preamble, however, the changes made elsewhere in these final regulations should make section 871(m) inapplicable to most convertible debt instruments, including those that are convertible securities subject to section 305(c).

3. Due Bills

The 2013 proposed regulations reserve on the question of whether a due bill gives rise to a dividend equivalent and request comments regarding whether a payment made by a seller of stock to the purchaser pursuant to an agreement to deliver a pending U.S. source dividend after the record date (for example, a due bill) should be treated as a substantially similar payment.

One comment noted that a due bill may give rise to payments that appear to satisfy the criteria for a dividend equivalent. That comment expressed concern regarding the impact this treatment might have on the capital markets because of the relative frequency of due bills, as well as the administrative complexity of treating these payments as dividend equivalents. Another comment asserted that a due bill is not the economic equivalent of a dividend. Both comments requested that the regulations either address due bills under the anti-abuse rule or exclude them from the term dividend equivalent.

The final regulations provide that a dividend equivalent does not include a payment made pursuant to a due bill that arises from the actions of a securities exchange that apply to all transactions in the stock and when the relevant exchange has set an ex-dividend date that occurs after the record date. This rule is expected to apply in situations in which a securities exchange sets an ex-dividend date after the record date to accommodate a special dividend.

4. Employee Compensation

The 2013 proposed regulations do not specifically exclude payments of compensation for personal services of a nonresident alien individual from being treated as a dividend equivalent. Comments suggested that compensation arrangements should be excluded from dividend equivalent treatment because compensation is already subject to an existing tax withholding framework, compensatory transactions arise in a different context from other derivatives and do not have the potential to avoid U.S. withholding tax, and compensation should be subject to tax where the services are performed.

The Treasury Department and the IRS have determined that section 871(m) should not apply to compensation that is generally subject to withholding or has a specific exception therefrom. Accordingly, the final regulations provide that a dividend equivalent does not include the portion of equity-based compensation for personal services of a nonresident alien individual that is wages subject to withholding under section 3402, excluded from the definition of wages under § 31.3401(a)(6)–1, or exempt from withholding under § 1.1441–4(b). For example, when a restricted stock unit is paid as compensation and tax is collected by the employer at the time of payment through withholding, the payment will not also be a dividend equivalent subject to withholding. If the restricted stock unit results in the receipt of stock, however, dividends subsequently paid on that stock would be subject to withholding under section 871.

5. Certain Corporate Acquisitions

In response to comments, § 1.871–15(j) of the 2013 proposed regulations provides an exception to the definition of a section 871(m) transaction when a taxpayer enters into a transaction as part of a plan pursuant to which one or more persons (including the taxpayer) are obligated to acquire more than 50 percent of the entity issuing the underlying securities.

Comments requested that the acquisition threshold in this exception be lowered from 50 percent to 10 or 20 percent. Comments noted that corporate acquisitions generally would not provide an opportunity for avoiding dividend withholding. Further, comments noted that the anti-abuse rule should be sufficient to address any abuse that could occur through such transactions. Comments acknowledged that when a target company pays a pre-closing dividend and the purchase price is reduced for the dividend, this may allow the purchaser to avoid a subsequent dividend. However, comments observed that this event should be viewed as a purchase price adjustment rather than a dividend equivalent.

The final regulations do not change the 50 percent threshold. Requiring that an acquisition (as part of a plan by one or more person) total more than 50 percent of a corporation is appropriate because it indicates that the primary intent of the acquirer is to obtain a controlling interest rather than just a substantial investment in the target company. In circumstances where a taxpayer enters into a transaction pursuant to which the taxpayer is obligated to acquire 50 percent or less of the entity issuing the underlying securities, and the transaction is a section 871(m) transaction, any party to the transaction that is a broker, dealer, or intermediary, a short party, or a withholding agent, must comply with any requirements in the final regulation to make appropriate determinations, and satisfy reporting and withholding obligations, as applicable.

D. Payment of a Dividend Equivalent

Section 871(m)(5) provides that a ''payment'' includes any gross amount that references a U.S. source dividend and that is used to compute any net amount transferred to or from the taxpayer. The 2013 proposed regulations provide that a dividend equivalent includes any amount that references an actual or estimated payment of a U.S. source dividend, whether the reference is explicit or implicit. Thus, in addition to amounts equal to actual payments of dividends and estimated dividends, a dividend equivalent includes any other contractual term of a section 871(m) transaction that is calculated based on an actual or estimated dividend. For example, when a long party enters into an NPC that provides for payments based on the appreciation in the value of an underlying security but that does not explicitly entitle the long party to receive payments based on regular dividends (a price return swap), the 2013 proposed regulations treat the price return swap as a transaction that provides for the payment of a dividend equivalent because the anticipated dividend payments are presumed to be taken into account in determining other terms of the NPC, such as in the payments that the long party is required to make to the short party or in setting the price of the underlying securities referenced in the price return swap.

Comments objected to the provisions in the 2013 proposed regulations that include estimated and implicit dividends in the definition of a dividend equivalent. These comments noted that an estimated dividend is reflected as a price reduction or as an amount that the foreign investor does not have to pay rather than an amount the foreign investor affirmatively receives for holding the derivative, which suggests that there is no ''payment'' of a dividend equivalent to the foreign investor. Comments also noted that, while estimated dividends may be implicitly incorporated into the pricing of a derivative, the price is ultimately determined by supply and demand in the market and the expected dividend is not always explicitly used in computing the amount paid.

The Treasury Department and the IRS have concluded that the economic benefit of a dividend is present in transactions that implicitly incorporate estimated dividends to virtually the same extent as transactions that pay or adjust for actual dividends. Thus, the final regulations retain the rules in the 2013 proposed regulations that include estimated and implicit dividends as dividend equivalents. *See* § 1.871–15(i)(2). More specifically, the final regulations provide that any gross amount that references the payment of a dividend, whether actual or estimated, explicit or implicit, is treated as a dividend equivalent to the extent of the amount determined under the regulations. The final regulations change the time that withholding is required on a payment of a dividend equivalent, as discussed in Part II.M of this preamble.

E. Amount of a Dividend Equivalent

1. *Calculation of Dividend Equivalent Amount*

Under the 2013 proposed regulations, the amount of a dividend equivalent for a specified NPC or specified ELI equals the per-share dividend amount with respect to the underlying security multiplied by the number of shares of the underlying security referenced in the contract (subject to adjustment), multiplied by the delta of the transaction with respect to the underlying security at the time when the amount of the dividend equivalent is determined. If a transaction provides for a payment based on an estimated or implicit estimated dividend, the actual dividend is used to calculate the amount of the dividend equivalent unless the short party identifies a reasonable estimated dividend amount in writing at the inception of the transaction. When a payment based on estimated dividends is supported by the required documentation, the per-share dividend amount used to compute the amount of a dividend equivalent is the lesser of the estimated dividend and the actual dividend.

Comments on the 2013 proposed regulations noted that recalculating the delta of a section 871(m) transaction each time the amount of a dividend equivalent is determined would add administrative complexity without necessarily improving accuracy. In the interest of simplicity, several comments recommended using the actual dividend amount rather than an amount adjusted for delta as the dividend equivalent amount. Other comments suggested using the delta at the time the transaction is issued or entered into for determining the dividend equivalent amount. For complex transactions for which the delta is indeterminate, comments suggested that withholding be based on the number of shares required by the short party to the transaction to hedge its initial position in the transaction.

The final regulations simplify the rules for determining the amount of a dividend equivalent in response to these comments. For a simple contract, the final regulations provide that the amount of the dividend equivalent for each underlying security equals the amount of the per-share dividend, multiplied by the number of shares referenced in the contract, multiplied by the applicable delta. In a change from the 2013 proposed regulations, the final regulations provide that this formula references the delta of the transaction at the time the simple contract is issued, rather than when the dividend is paid. For a complex contract, the amount of the dividend equivalent equals the amount of the per-share dividend multiplied by the number of shares that constitute the initial hedge of the complex contract (as that term is defined in § 1.871–15(a)(14)(ii) and discussed in Part III.A of this preamble).

Another simplifying rule applies to dividend equivalents paid with respect to baskets of more than 25 securities. If a section 871(m) transaction references a basket of more than 25 underlying securities, the short party is allowed to treat all of the dividends on the basket as paid on the last day of the calendar quarter.

2. *Specified NPCs and Specified ELIs With a Term of One Year or Less*

For a specified NPC or specified ELI with a term of one year or less when acquired, the 2013 proposed regulations provide that the amount of a dividend equivalent is determined when the long party disposes of the section 871(m) transaction. Therefore, a long party that acquires an option with a term of one year or less that is a specified ELI would not incur a withholding tax if the option lapses.

One comment noted that the rule providing that there is no dividend equivalent for options that have a term of one year or less and lapse unexercised is inappropriate in the case of written put options because put writers realize their maximum profit when puts lapse. Comments further noted that the one-year rule could have uneconomic consequences for options close to expiration and for options that are slightly in-the-money or slightly out-of-the-money because the delta could fluctuate materially in response to small changes in the price of the underlying stock.

Based on the comments received, the final regulations eliminate the special rule for contracts with terms of one year or less. Any benefit from the rule is outweighed by the complexity of creating systems to track contracts that differ only in term. Eliminating the special rule for contracts of one year or less means that a dividend equivalent amount must be determined for any option, including a short-term option, that is a specified ELI.

F. Qualified Indices

The 2013 proposed regulations revise rules provided in the 2012 proposed regulations pertaining to an exception for transactions that reference certain equity indices. Under the 2013 proposed regulations, a qualified index is any index that (1) references 25 or more underlying securities, (2) references only long positions in underlying securities, (3) contains no underlying security that represents more than 10 percent of the index's weighting, (4) rebalances based on objective rules at set intervals, (5) does not provide a dividend yield that is greater than 1.5 times the dividend yield of the S&P 500 Index, and (6) is referenced by futures or option contracts that trade on a national securities exchange or a domestic board of trade. In addition, the 2013 proposed regulations provide that a qualified index would become disqualified if a transaction references a qualified index and also references a short position in any component underlying security of the qualified index other than a short position with respect to the entire qualified index (such as a cap or a floor).

One comment recommended eliminating the exception for a qualified index. This comment noted that when a long party holds a total return swap referencing a basket of underlying securities, that swap is economically equivalent to multiple total return swaps that each reference a single underlying security. Similarly, when a long party holds a delta-one derivative that references an index, that derivative is economically equivalent to multiple delta-one derivatives each referencing a single component of the index; therefore, that long party is receiving the economic equivalent of all dividends paid with respect to each stock in the index. Thus, transactions that reference U.S. stock indices have no less potential for avoidance of gross basis withholding tax on dividends than transactions that reference single equities or that reference customized baskets of equities.

Another comment noted that the criteria in the 2013 proposed regulations provide a reasonable method for identifying legitimate indices that have not been designed to avoid withholding taxes. That comment noted that the rules would exclude most securities that are linked to an index and traded on U.S. stock exchanges from dividend taxation, while preventing customized indices from becoming a vehicle designed to evade U.S. dividend taxes.

The majority of comments, however, recommended that the scope of the index exception be expanded to include most of the indices that are represented by exchange traded funds. Several comments requested that the definition allow an index with fewer than 25 stocks to be a qualified index, noting that many sector indices have fewer than 25 names. Another comment suggested providing an exception to the requirement that an index be referenced by exchange-traded futures or options that would apply to indices that are sufficiently broad-based (for example, indices containing one hundred or more component securities). Comments also suggested eliminating the requirement that the stock of a single company cannot represent more than 10 percent of the index's weighting because some indices include component securities that grow rapidly. Several comments also noted that many indices would fail to satisfy the requirement that a qualified index rebalance based on objective rules at set intervals because many popular indices, including the S&P 500 Index, rebalance using a combination of objective and subjective factors.

Comments further requested that the permitted dividend yield be increased to 2.5 times the current dividend yield of the S&P 500 Index. The comments noted that an index may not satisfy the requirement based on 1.5 times the current dividend yield of the S&P 500 Index if the stocks in the index depreciated significantly relative to the general U.S. stock market. In addition, other indices would not qualify because some market sectors routinely pay dividends at a rate that is more than 1.5 times the average rate in the U.S. market.

Other comments suggested additional categories of indices that should be treated as qualified indices. Specifically, one comment recommended that any index that was published by a recognized independent index publisher should be a qualified index if the index is offered for license to third parties on similar terms and multiple third party industry participants actually license the index. The comments proposed defining a recognized independent index publisher as an organization that publishes indices that are created, calculated, and compiled by a group of employees that have no duties other than those related to the publication of the indices.

The rule in the 2013 proposed regulations that prevents taxpayers from using short positions to decrease their long position with respect to one or more components of an index was also noted by comments as too restrictive. Comments suggested permitting taxpayers to decrease risk with respect to a small percentage of the value of the stocks in the index without disqualifying the index. One comment suggested that an index should remain a qualified index unless the short position is used to establish a net long position in a narrow set of underlying securities for purposes of evading withholding.

The 2013 proposed regulations also included a safe harbor for global indices with 10 percent or less U.S. stocks. Comments recommended expanding this safe harbor because U.S. equities in a global index can comprise more than half of the index's weighting. The comments proposed increasing the threshold to allow U.S. stocks to represent 50 percent or more of the index. These comments also noted that global indices do not typically trade on U.S. securities or commodities exchanges and will not be qualified indices under the current provisions. Other comments suggested that the regulations except from withholding all global indices that are not created to avoid withholding tax, with a presumption that widely-used benchmark indices are not designed to avoid tax.

The Treasury Department and the IRS believe that the approach taken in the 2013 proposed regulations for identifying qualified indices appropriately balances the competing concerns. Accordingly, the final regulations generally retain the criteria of the 2013 proposed regulations with modifications to clarify the intent and improve the functionality of the qualified index rule. *See* § 1.871–15(l)

The final regulations add a paragraph stating that the purpose of the qualified index rule is to provide a safe harbor for transactions on passive indices that reference a diverse basket of securities and that are widely used by numerous market participants. The index exception is not intended to apply to any index that is customized or reflects a trading strategy, is unavailable to other investors, or targets special dividends. The final regulations further provide that an index will not be treated as a qualified index if treating the index as a qualified index would be contrary to this purpose.

To make the rules easier to administer, the final regulations modify the time for determining whether an index satisfies the qualified index criteria. Specifically, the final regulations provide that the determination of whether an index is a qualified index is made on the first business day of each calendar year, and that determination applies for all potential section 871(m) transactions issued during that calendar year.

In response to comments, a number of changes also were made to specific aspects of the qualified index definition. First, the final regulations delete the modifier ''underlying'' with respect to ''securities,'' thereby allowing an index to qualify with fewer than 25 component underlying securities provided that the index contains a total of at least 25 component securities (in other words, a component security may include a security that does not give rise to U.S. source dividends). The index, however, will not qualify if it references five or fewer component underlying securities that together represent more than 40 percent of the weighting of the component securities in the index. Second, the final regulations increase the 10 percent limit for the maximum weighting of a single underlying security to 15 percent. Third, in response to concerns regarding the requirement that a qualified index rebalance based on objective rules, the final regulations do not require that an index be modified or rebalanced at set dates or intervals, and provide flexibility for how the rules governing the constitution of an index are applied. Instead, under the final regulations, an index that is periodically rebalanced by a board or committee that is allowed to exercise judgment in interpreting the rules governing the composition of the index will not be disqualified if the index is otherwise a qualified index.

The final regulations continue to require that an index be referenced by futures or options listed on a national securities exchange or board of trade to be a qualified index, which is consistent with the intent to provide a safe harbor only for non-customized and widely-available indices. The final regulations do, however, permit an index that trades on certain foreign exchanges to be a qualified index, provided that the referenced component underlying securities, in aggregate, comprise less than 50 percent of the weighting of the component securities in the index and the index otherwise meets the definition of a qualified index.

Similarly, the Treasury Department and the IRS have concluded that the proposed rule permitting no more than 1.5 times the current dividend yield of the S&P 500 Index is appropriate and have retained it in the final regulations. To reduce the number of required calculations, however, the final regulations provide that the annual yields of the tested index and of the S&P 500 Index are determined based on their annual yields for the immediately preceding calendar year, rather than requiring comparison of the annual yields for the month immediately preceding the date that the potential section 871(m) transaction is issued.

The Treasury Department and the IRS agree that de minimis short positions, whether as part of the index or entered into separately, should not disqualify an index. Accordingly, the final regulations permit a qualified index to reference one or more short positions (in addition to any short positions with respect to the entire qualified index, such as caps or floors, which were already permitted by the 2013 proposed regulations) that represent five percent or less, in the aggregate, of the value of the long positions in underlying securities in the qualified index.

G. Combined Transactions

The 2013 proposed regulations treat multiple transactions as a single transaction for purposes of determining if the transactions are a section 871(m) transaction when a long party (or a related person) enters into two or more transactions that reference the same underlying security and the transactions were entered into in connection with each other. The 2013 proposed regulations apply only to combine transactions in which the taxpayer is the long party, and typically would not combine transactions when a taxpayer is the long party with respect to an underlying security in one transaction and the short party with respect to the same underlying security in another transaction. The 2013 proposed regulations provide that a broker-dealer must use ''reasonable diligence'' to determine whether a transaction is a section 871(m) transaction. Under the 2013 proposed regulations, a withholding agent was not required to withhold on a dividend equivalent paid pursuant to a transaction that is combined with one or more other transactions unless the withholding agent knew that the long party (or a related person) entered into the potential section 871(m) transactions in connection with each other.

The Treasury Department and the IRS requested comments regarding whether and how the rules for combining separate transactions should apply in other situations, such as when a taxpayer holds both long and short positions with respect to the same underlying security (for example, a call spread). Comments also were requested regarding whether and how the remaining transaction (or transactions) should be retested when a long party terminates one or more, but not all, of the transactions that make up a combined position.

Several comments recommended that the regulations not provide a specific combination rule and instead rely on an anti-abuse rule. One comment endorsed the proposed regulations as they applied to combinations of long calls and written puts (two options that can be used to closely approximate the economics of stock ownership) but recommended that transactions not be combined if the transactions replicate the same or similar risks with respect to additional shares (for example, two purchased calls on the same underlying securities).

Many comments observed that determining whether transactions were entered into ''in connection with'' each other would be difficult for a withholding agent and that the regulations should adopt a different standard or clarify the meaning of the phrase. Comments asked that the final regulations conform the standard for combined transactions to the narrower withholding standard that requires ''actual knowledge.'' Comments noted that the requirement in the 2013 proposed regulations for broker-dealers to use ''reasonable diligence'' to determine whether a transaction is a section 871(m) transaction could be interpreted to require broker-dealers to inquire whether transactions are entered into in connection with each other in order to determine whether they must be combined. These comments observed that this standard for combined transactions is impractical because broker-dealers are generally not in a position to discern the intent of their counterparties, even using ''reasonable diligence.''

Several comments recommended that a combination rule permit netting of long and short positions. Commenters observed that many standard option strategies involve multiple options positions, often combining positive and negative delta options. As a result, an approach that does not combine these positions would fail to reflect the economics of the transactions. Commenters suggested that when a taxpayer modifies an existing combined position that includes both long and short positions, the combined position should continue to be tested based on the net deltas of the component positions rather than test the delta for each position separately. None of the comments, however, proposed an administrable test that could be used to reliably combine long and short positions and net the resulting deltas.

The final regulations retain the general rules from the 2013 proposed regulations that define when transactions are combined. In response to questions about whether the rules were intended to combine transactions that had similar economic exposure, the final regulations add a requirement that the potential section 871(m) transactions, when combined, replicate the economics of a transaction that would be a section 871(m) transaction if the transactions had been entered into as a single transaction. Thus, the purchase of two out-of-the-money call options would typically not be combined because each call option provides the taxpayer with exposure to appreciation, but not depreciation, on the referenced stock.

The Treasury Department and the IRS recognize the challenges that short parties could face in identifying transactions to be combined. The final regulations therefore provide brokers acting as short parties with two presumptions they can apply to determine their liability to withhold. First, a broker may presume that transactions are not entered into in connection with each other if the long party holds the transactions in separate accounts. Second, a broker may presume that transactions entered into two or more business days apart are not entered into in connection with each other. These presumptions are independent of each other. Thus, a broker acting as a short party is relieved of the obligation to withhold if either of the two presumptions is met. A broker cannot rely on the first presumption if it has actual knowledge that the long party created or used separate accounts to avoid section 871(m), however, and neither presumption applies if the broker has actual knowledge that transactions were entered into in connection with each other.

In addition, the final regulations provide that the Commissioner will presume that transactions that are properly reflected on separate trading books of the taxpayer are not entered into in connection with each other. The Commissioner will also presume that a long party did not enter into two or more transactions in connection with each other if the long party entered into the transactions two or more business days apart. These presumptions are rebuttable. The Commissioner may rebut the first presumption with facts and circumstances showing that separate trading books were created or used to avoid section 871(m), and may rebut either presumption with facts and circumstances showing that the transactions in question were entered into in connection with each other.

The Commissioner will also apply an affirmative presumption. The Commissioner will presume that transactions that are entered into fewer than two business days apart and reflected on the same trading book are entered into in connection with each other. In this case, the long party can rebut the presumption by presenting facts and circumstances showing that the transactions were not entered into in connection with each other. In applying the presumptions that are based on trades being separated by at least two business days, the regulations include a rule of convenience that generally allows parties to treat all of their transactions as entered into at 4:00 p.m.

The presumptions are not available to the long party. A long party therefore must treat two or more transactions as combined transactions if the transactions satisfy the requirements to be a combined transaction. The long parties affected by this rule consist primarily of securities traders, who are in a position to know their securities positions and trading strategies and to monitor their compliance with section 871(m).

The Treasury Department and the IRS will continue to evaluate the possibility of expanding the combination rules to accommodate netting of long and short positions in light of future developments in transactional reporting and recordkeeping. Additional comments regarding combined transactions are welcome.

H. Derivatives Referenced to Partnership Interests

The 2013 proposed regulations treat a transaction that references an interest in an entity that is not a C corporation for Federal tax purposes as referencing the allocable portion of any underlying securities and potential section 871(m) contracts held directly or indirectly by that entity. The 2013 proposed regulations provide an exception for a transaction that references an interest in an entity that is not a C corporation if the underlying securities and potential section 871(m) transactions allocable to that interest represent, in the aggregate, 10 percent or less of the value of the interest in the referenced entity at the time the transaction is entered into. Comments recommended changing the threshold for applying the look-through rule from 10 percent to 50 percent unless the taxpayer controls the entity. Comments also noted that taxpayers would have difficulty determining the assets owned by referenced entities.

The final regulations revise the rules to provide that section 871(m) applies to derivatives that reference a partnership interest only when the partnership is either a dealer or trader in securities, has significant investments in securities, or holds an interest in a lower-tier partnership that engages in those activities. The final regulations define a security by cross-reference to section 475(c). When the rule in the final regulations applies, a potential section 871(m) transaction that references a partnership interest is treated as referencing the allocable share of underlying securities and the potential section 871(m) transactions in the partnership directly or indirectly allocable to that partnership interest. Even when a partnership is not covered by this rule, the anti-abuse rule in § 1.871–15(o) may still apply, or the transaction may be recharacterized under the substance-over-form doctrine or other common law doctrine.

I. Anti-Abuse Rule

The 2013 proposed regulations provide that the Commissioner may treat any payment made with respect to a transaction as a dividend equivalent if the taxpayer acquires the transaction with a principal purpose of avoiding the application of section 871(m). Comments generally agreed with the need for such a rule, and the final regulations retain this provision. *See* § 1.871–15(o).

In addition, the IRS may challenge the U.S. tax results claimed in connection with transactions that are designed to avoid the application of section 871(m) using all available statutory provisions and judicial doctrines (including the substance-over-form doctrine, the economic substance doctrine under section 7701(o), the step transaction doctrine, and tax ownership principles) as appropriate. For example, nothing in section 871(m) precludes the IRS from asserting that a contract labeled as an NPC or other equity derivative is in fact an ownership interest in an underlying security referenced in the contract.

J. Reporting Obligations

The 2013 proposed regulations provide rules for reporting and withholding. The preamble to the 2013 proposed regulations explains that most equity-linked transactions involve a financial institution acting as a broker, dealer, or intermediary and that the financial institution would be in the best position to report the tax consequences of a potential section 871(m) transaction. Accordingly, § 1.871–15(o) of the 2013 proposed regulations provides that when a broker or dealer is a party to a potential section 871(m) transaction the broker or dealer is required to determine whether the transaction is a section 871(m) transaction, and if so, the amounts of the dividend equivalents. If no broker or dealer is a party to a transaction or both parties are brokers or dealers, the short party is required to determine whether the transaction is a section 871(m) transaction and the amounts of the dividend equivalents. Determinations made by the broker, dealer, or short party are binding on the parties to the section 871(m) transaction unless a party to the transaction knows or has reason to know that the information is incorrect. Those determinations, however, are not binding on the IRS.

Comments expressed concern that the delta information necessary for an investor to determine whether a transaction is subject to section 871(m) may not be available on a timely basis, and requested that the regulations expand the categories of persons permitted to request information about the status and calculations associated with potential section 871(m) transactions. Comments recommended requiring the information to be provided on an issuer's Web site at or prior to the time that the transaction is issued and updated regularly. Investors could then rely on such information between update intervals.

In response to these comments, the final regulations make several changes to the reporting obligations in the 2013 proposed regulations. The final regulations revise the period for providing requested information from 14 calendar days to 10 business days from the date of the request. In addition, the final regulations replace the list of persons entitled to request information in the 2013 proposed regulations with a simpler provision that entitles ''any party to the transaction'' to request information. The final regulations define ''a party to the transaction'' to include any agent acting on behalf of a long party or short party to a potential section 871(m) transaction, or any person acting as an intermediary with respect to a potential section 871(m) transaction. This simplification responds to the requests to expand the scope of persons entitled to request information. Several other changes that were requested, however, such as posting information electronically, were already permitted by the 2013 proposed regulations. Like the 2013 proposed regulations, the final regulations permit parties to a transaction to obtain information on potential section 871(m) transactions in a variety of ways, including through electronic publication (such as a Web site).

Comments also noted that a short party to a listed option will not be able to provide the long party with a written estimate of dividends at inception because the short party does not have a contractual relationship with the long party. These comments requested that the broker be required to provide the written estimates. As in the 2013 proposed regulations, the final regulations do not require any party to a transaction to provide written estimates of dividends. The final regulations have taken these comments into account, however, by increasing a taxpayer's ability to obtain information from other parties to the transaction. The final regulations accomplish this by expanding the definition of a ''party to the transaction'' to include a broker and by clarifying that either a dealer or a middleman is a ''broker.'' Therefore, if written estimates of dividends are prepared when a transaction is issued, the long party should be able to obtain the information from another party to the transaction, whether the short party or a broker.

K. Recordkeeping Rules

The 2013 proposed regulations generally cross-reference the recordkeeping rules in § 1.6001–1 for how a taxpayer establishes whether a transaction is a section 871(m) transaction and whether a payment is a dividend equivalent. For clarity and to ensure that the IRS will have access to sufficient information to audit taxpayers and withholding agents that are parties to section 871(m) transactions, the final regulations provide more detailed recordkeeping rules. The final regulations provide that any person required to retain records must keep sufficient information to establish whether a transaction is a section 871(m) transaction and the amount of a dividend equivalent. To satisfy this requirement, a taxpayer must retain documentation and work papers supporting a delta calculation or substantial equivalence calculation (including the number of shares of the initial hedge) and written estimated dividends (if any). The records and documentation must be created substantially contemporaneously with the time the potential section 871(m) transaction is issued.

L. Contingent and Convertible Debt Instruments

1. Contingent Debt Instruments

Section 871(h)(1) generally provides that U.S. source portfolio interest received by a nonresident alien individual is not subject to the 30-percent U.S. tax imposed under section 871(a)(1). Section 871(h)(4)(A)(i), however, excludes certain contingent interest payments from the definition of portfolio interest. Section 871(h)(4)(A)(ii) grants the Secretary authority to impose tax on contingent interest other than the payments described in section 871(h)(4)(A)(i) when necessary or appropriate to prevent the avoidance of federal income tax.

Comments on the 2012 proposed regulations recommended narrowing the definition of a specified notional principal contract to clarify that the term does not include contingent or convertible debt. These comments suggested that section 871(m) should not override the portfolio interest exception. Section 871(h)(4)(A)(ii) expressly provides authority to the Secretary to treat interest as contingent interest if necessary or appropriate to prevent the avoidance of federal income tax. Consistent with this grant of authority, the 2013 proposed regulations provide that contingent interest will not qualify for the portfolio interest exemption to the extent that the contingent interest payment is a dividend equivalent. The final regulations retain this exception to the portfolio interest exemption. There is no reason that an equity derivative that otherwise would be a specified NPC or a specified ELI should receive different treatment because it is embedded in a debt instrument. A debt instrument that provides for a contingent interest payment determined by reference to a U.S. source dividend payment that would otherwise be a section 871(m) transaction is a transaction that has the potential for tax avoidance, and it is appropriate for section 871(m) to apply. The effect of this rule, however, is expected to be minimal because the delta of the embedded derivative in a contingent debt or convertible debt instrument is tested only at the time it is issued.

2. Convertible Debt Instruments

Numerous comments requested that convertible debt instruments be excluded from the definition of an ELI. Comments suggested that certain characteristics typical of convertible debt would discourage foreign investors from using these instruments to avoid U.S. withholding tax. Comments pointed, for example, to high transaction costs and certain discontinuities between the economic performance of the convertible debt and that of the underlying stock, such as the downside protection and creditors' rights afforded by convertible debt. Comments noted that convertible bonds are important capital markets instruments used by U.S. corporations to raise capital at lower rates. Comments also speculated that treating such bonds as specified ELIs could adversely impact capital markets by decreasing demand, reducing liquidity, and increasing costs.

The final regulations do not provide an exception from section 871(m) for convertible debt. When the stock price significantly exceeds the conversion price, convertible debt becomes a surrogate for the stock into which the debt can be converted. Accordingly, a convertible debt obligation is a specified ELI if the delta of the embedded option at the time the convertible debt is originally issued is 0.80 or higher. Moreover, the fact that convertible debt ordinarily has been issued with a delta on the embedded option of less than 0.80 is expected to significantly reduce the effect of these regulations on the convertible debt market. In response to uncertainty expressed by some market participants, the final regulations clarify that the delta of the convertible feature is tested separately from the delta of the debt instrument in making section 871(m) calculations.

M. Amounts Subject to Withholding

Section 1.1441–2(d)(5) of the 2013 proposed regulations provides that a withholding agent is not obligated to withhold on a dividend equivalent until the later of: (1) When the amount of the dividend equivalent is determined and (2) when any of the following occurs: (a) Money or other property is paid pursuant to a section 871(m) transaction, (b) the withholding agent has custody or control of money or other property, or (c) there is an upfront payment or a prepayment of the purchase price.

Comments emphasized the burden of withholding on dividend equivalents absent actual payments, and noted that, in the absence of actual payment, continuous monitoring and withholding on each specified ELI over time is impractical. Certain comments suggested that a foreign broker only be required to withhold on dividend equivalents from ELIs when there is a final payment or a sale.

Comments also maintained that upfront payments should not be viewed as payments subject to withholding because such proceeds are received in exchange for issuing the instrument, are used by the issuer to purchase related hedging positions, and are not intended to be reserves for satisfying tax owed by the counterparty.

Some comments expressed concern regarding the practical difficulties in withholding from funds that the broker-dealer holds as collateral. Comments noted that the broker-dealer may not be legally entitled to use cash or property in one account to satisfy a withholding obligation in another account. In addition, foreign counterparties may hold different accounts through different affiliates of a broker-dealer. Comments indicated that it would be impractical to determine the existence of affiliate accounts and apply set-off rules on that basis.

After consideration of these comments, the Treasury Department and the IRS have concluded that the withholding agent's obligations should not arise until an actual payment is made or there is a final settlement of a transaction. Accordingly, the final regulations provide that a withholding agent is not obligated to withhold on a dividend equivalent until the later of when a payment is made with respect to a section 871(m) transaction or when the amount of a dividend equivalent is determined. A payment with respect to a section 871(m) transaction will generally occur when the long party receives or makes a payment, when there is a final settlement of the section 871(m) transaction, or when the long party sells or otherwise disposes of the section 871(m) transaction. For options and other contracts that typically require an upfront payment, the final regulations do not treat the premium or other upfront payment as a payment for withholding purposes. Thus, withholding on these section 871(m) transactions is not required until there is a final settlement (including, in the case of an option, a lapse) or the long party sells or otherwise disposes of the transaction. Consequently, if an option that is a section 871(m) transaction lapses, the short party is nonetheless required to withhold on any dividend equivalent associated with the option. Parties may need to modify contractual arrangements to ensure that there are sufficient funds available to satisfy withholding obligations.

III. Temporary and Proposed Regulations

A. Test for Contracts With Indeterminate Deltas

As noted in Part II of this preamble, many commenters stated that the delta test was workable for most equity derivatives but would be difficult or impossible to apply to more exotic equity derivatives. In particular, a contract that provides for payments based on a number of shares of stock that varies at different points, or that provides for a payment that does not vary with the price of the shares (often called ''digital'' options), have an indeterminate delta because the number of shares of the underlying security that determine the payout of the derivative cannot be known at the time the contract is entered into. Path-dependent contracts were also mentioned as problematic for the delta computation.

Indeterminate delta may, for example, occur in contracts commonly known as structured notes. Structured notes are financial instruments that combine aspects of debt with aspects of derivatives, such as equity options. As an example, in return for an upfront payment of a set amount, a structured note might provide the long party with leveraged upside return, meaning that the long party is entitled to receive a fixed percentage (for example, 200 percent) of any appreciation in the value of a referenced stock up to a capped amount (for example, 125 percent of the issue price) in addition to return of the upfront payment, while being exposed to 100 percent of any depreciation in the value of the referenced stock, with any such depreciation reducing the amount of the upfront payment that is returned to the long party. In such a structured note, the holder would have two times the ''upside'' up to the cap but only one times exposure to the ''downside.'' The issuer of this kind of structured note cannot readily determine a delta for the note because it references a different number of shares at different payoff amounts. In other words, because delta is the ratio of the change in the fair market value of a contract to a small change in the fair market value of the property referenced by the contract, the value of the referenced property must be known to calculate delta. In the case of the structured note described in this paragraph, the number of shares of stock (and hence the value of the property) referenced by the contract will be different depending on whether the stock appreciates, and in such case whether the cap is reached, or whether the stock depreciates.

As explained in Part II.C.4 of this preamble, a contract with an indeterminate delta is not a simple contract, and therefore falls into the residual category as a complex contract. Because the delta test cannot accurately be applied to a complex contract, commenters had various suggestions for how to determine whether such a contract should be a section 871(m) transaction. One comment suggested that the delta should be calculated using the highest possible number of shares that could be referenced by the derivative at maturity. This comment further suggested that the regulations include a delta-specific anti-abuse rule to prevent issuers from manipulating the number of referenced shares to artificially reduce delta. Other comments suggested that the regulations should disaggregate a transaction into a series of components and then separately apply the delta test to each component. When multiple derivatives are embedded in a single instrument, a comment recommended that multiple pieces be aggregated into separate components (for example, aggregating all embedded calls and separately aggregating all embedded puts) using an ordering rule that would maximize the likelihood that the delta threshold would be met.

A majority of comments requested that some version of a ''proportionality'' test be applied to complex contracts or to contracts where the basic delta test is susceptible of manipulation. A proportionality test measures the likelihood that a contract's performance will track the performance of the referenced equity. That is, a proportionality test measures the same variability or economic equivalence that the delta test seeks to measure without needing to know the number of shares that the contract references at the outset. Like the delta test, a proportionality test is based on the principle that when the value of an NPC or ELI closely tracks the value of an underlying security, it is appropriate to treat the NPC or ELI as a surrogate for the underlying security.

To test whether a complex contract is a section 871(m) transaction, the temporary regulations adopt the ''substantial equivalence'' test. The substantial equivalence test is a version of a proportionality test that was advocated by many commenters, and it uses information easily accessible to most issuers of complex contracts. Generally, the substantial equivalence test measures the change in value of a complex contract when the price of the underlying security referenced by that contract is hypothetically increased by one standard deviation or decreased by one standard deviation (each, a ''testing price'') and compares that change to the change in value of the shares of the underlying security that would be held to hedge the complex contract at the time the contract is issued (the ''initial hedge'') at each testing price. The smaller the proportionate difference between the change in value of the complex contract and the change in value of its initial hedge at multiple testing prices, the more equivalence there is between the contract and the referenced underlying security. When this difference is equal to or less than the difference for a simple contract benchmark with a delta of 0.80 and its initial hedge, the complex contract is treated as substantially equivalent to the underlying security.

The Treasury Department and the IRS are aware that there may be NPCs or ELIs that even the substantial equivalence test may not adequately address. The temporary regulations provide that when the steps of the substantial equivalence test cannot be applied to a particular complex contract, a taxpayer must use the principles of the substantial equivalence test to reasonably determine whether the complex contract is a section 871(m) transaction with respect to each underlying security.

The Treasury Department and the IRS request comments regarding the substantial equivalence test described in the temporary regulations. In particular, comments are requested on whether the two testing points required for most transactions in the temporary regulations are adequate to ensure that the substantial equivalence test captures the appropriate types of transactions, and the administrability of the test and its application to complex contracts that reference multiple securities, including path-dependent instruments.

B. Withholding Requirements and QDDs

1. Background

Section 871(m)(1) generally treats a dividend equivalent as a dividend from sources within the United States without regard to the residence of the person paying the dividend equivalent. As a result, section 871(m) may apply to payments made by a foreign payor to a foreign payee. *See* Staff of J. Comm. on Taxation, Technical Explanation of the Revenue Provisions Contained in Senate Amendment 3310, the ''Hiring Incentives to Restore Employment Act,'' JCX–4–10, at 79 (Feb. 23, 2010) (explaining that section 871(m) may apply to a chain of dividend equivalents, including payments made by a foreign person pursuant to transactions described in Notice 97–66); *see also* Notice 97–66, 1997–2 C.B. 328, at § 5, Examples 3 and 4 (illustrating that a foreign person making a substitute dividend payment to another foreign person must withhold U.S. tax). Because Congress was concerned that this rule may result in over-withholding in some instances, Congress granted the Secretary authority in section 871(m)(6) to reduce tax on a chain of dividend equivalents, but only to the extent that the taxpayer can establish that tax has been paid with respect to another dividend equivalent in the chain, or is not otherwise due, or as the Secretary determines is appropriate to address the role of financial intermediaries in such chain. For purposes of section 871(m)(6), a dividend is treated as a dividend equivalent.

2. Comments on the 2013 Proposed Regulations

The 2013 proposed regulations address the role of financial intermediaries in a chain of dividend equivalents with a rule that provides that payments made to a ''qualified dealer'' are not treated as dividend equivalents if made pursuant to a transaction that is entered into by the qualified dealer in its capacity as a dealer in securities and the dealer is the long party. For purposes of this rule, a qualified dealer is any dealer that is subject to regulatory supervision by a governmental authority in the jurisdiction in which it was created or organized and that certifies to the short party that it is receiving the payment in its capacity as a dealer. The 2013 proposed regulations require the qualified dealer to certify as to its dealer status to a short party on a transaction-by-transaction basis, and do not apply to dividends paid to a qualified dealer.

Comments requested that the qualified dealer exception in the 2013 proposed regulations be expanded, noting that it would be impractical for dealers to certify that each transaction was entered into in a dealer capacity (and not as a proprietary trade) and that the rule did not accommodate transactions entered into as a hedge of another transaction. Some comments suggested that the regulations exclude transactions entered into in the ordinary course of the dealer's business for hedging purposes. Other comments recommended expanding the exception to include affiliates of qualified dealers that issue certain potential section 871(m) transactions. Comments further recommended that an affiliate in these circumstances should not be required to certify that it is acting in its capacity as a dealer. Several comments requested that, in addition to expanding the definition of qualified dealer, the final regulations provide rules similar to the proposed regulatory framework described in Notice 2010–46 (discussed in more detail in section III.B.4 of this preamble).

3. Qualified Intermediaries Acting as Qualified Derivatives Dealers

The comments received on both the 2012 proposed regulations and the 2013 proposed regulations consistently expressed the desire for a comprehensive withholding and documentation regime tailored to derivatives dealers. Rather than create a new regime for section 871(m) transactions, the Treasury Department and the IRS determined that the most comprehensive and efficient way to respond to the requests in the comments is to expand the existing qualified intermediary (QI) regime to accommodate taxpayers acting as financial intermediaries on section 871(m) transactions. Generally, a QI is an eligible person that enters into a QI agreement with the IRS and that acts as a QI under such agreement. *See* Rev. Proc. 2014–39, 2014–29 I.R.B. 150. A QI agreement typically requires the QI to assume certain documentation and withholding responsibilities in exchange for simplified information reporting for its foreign account holders and the ability to not disclose proprietary account holder information to a withholding agent that may be a competitor. A QI may either assume primary withholding responsibilities or may provide withholding information to a withholding agent from which it receives a payment.

QIs that hold stocks and bonds for customers often receive payments subject to withholding on behalf of their foreign account holders as custodians rather than as beneficial owners. In contrast, a broker that enters into derivative contracts as a principal typically receives dividends and dividend equivalents as part of a chain of transactions in which the broker is a counterparty to both long and short positions.

The Treasury Department and the IRS intend to implement the particular requirements of withholding and reporting on dividend equivalents received and paid by brokers by amending the QI agreement to include new provisions that will permit an eligible QI to act as a qualified derivatives dealer (QDD). A QI that acts as a QDD will not be subject to withholding on dividends or payments that may be dividend equivalents made with respect to potential section 871(m) transactions that the QDD receives while acting in its capacity as a dealer.

In order to act as a QDD, a QI must meet four requirements. First, the QDD must furnish to withholding agents a QI withholding certificate affirming that the recipient is acting as a QDD for dividends and dividend equivalent payments associated with the withholding certificate. Second, the QDD must agree to assume primary withholding and reporting responsibilities on all payments associated with the withholding certificate that the QDD receives and makes as a dealer, and to determine whether payments it makes are dividend equivalents. Third, a QDD must agree to remain liable for tax on any dividends and dividend equivalents it receives unless the QDD is obligated to make an offsetting dividend equivalent payment as the short party on the same underlying securities. Finally, a QDD must comply with any compliance review procedures that are applicable to a QI acting as a QDD, as specified in the QI agreement.

The class of persons eligible to act as a QDD is narrower than the class of persons that are eligible to enter into a QI agreement. A QI will be allowed to act as a QDD if it is either (1) a securities dealer that is regulated as a dealer in the jurisdiction in which it was organized or operates, or (2) a bank that is regulated as a bank in the jurisdiction in which it was organized or operates (or a wholly-owned foreign affiliate of such a bank). To act as a QDD, a QI that is not a securities dealer also must issue potential section 871(m) transactions to customers and receive dividends or dividend equivalent payments incident to hedges of potential section 871(m) transactions that it issues. The latter category of QDDs is intended to allow banks and bank affiliates that issue equity-linked instruments on an occasional basis to still act as QDDs.

4. Notice 2010–46

Shortly after section 871(m) was enacted, the Treasury Department and the IRS published Notice 2010–46, 2010–24 I.R.B. 757. Notice 2010–46 addresses potential overwithholding in the context of securities lending and sale repurchase agreements. Notice 2010–46 provides a two-part solution to the problem of overwithholding on a chain of dividends and dividend equivalents. First, it provides an exception from withholding for payments to a qualified securities lender (QSL). Second, it provides a proposed framework to credit forward prior withholding on a chain of substitute dividends paid pursuant to a chain of securities loans or stock repurchase agreements. The QSL regime requires a person that agrees to act as a QSL to comply with certain withholding and documentation requirements. Notice 2010–46 and any QI agreement imposing QSL requirements will remain effective until final regulations implementing the QDD rules are published.

As stated above, Notice 2010–46 provided a proposed framework to credit forward prior withholding on a chain of substitute dividends paid pursuant to a chain of securities loans or stock repurchase agreements. The Treasury Department and the IRS will continue to consider whether a credit forward system for prior withholding would be appropriate in the context of a chain of dividend equivalents on NPCs or ELIs. While administrating the credit forward system described in Notice 2010–46, however, the IRS has had difficulty verifying that prior withholding in a chain of securities loans had in fact occurred in order to justify the crediting of prior withholding to a subsequent payment. The temporary regulations, therefore, reserve on the issue of a general credit forward system, and the Treasury Department and the IRS request comments on the need for such a system and how it could be implemented.

5. Implementation of the QDD Regime and Phase-out of the QSL Regime

All existing QI agreements expire on December 31, 2016. Prior to January 1, 2017, the Treasury Department and the IRS intend to publish an updated QI agreement and rules addressing the requirements for QDD status.

Procedures for entering into a QI agreement that permits a QI to act as a QDD are expected to be set out in this agreement. QDD status will be effective no sooner than January 1, 2017. Until these temporary regulations are finalized and appropriate provisions are incorporated into a new QI agreement, the provisions for QSLs and the credit-forward rules under Notice 2010–46 will continue to apply for dividend equivalents that are substitute dividend payments made pursuant to a securities lending or a sale-repurchase transaction.

Once fully implemented, the new QDD status under the QI regime will replace and expand the QSL regime described in Notice 2010–46. To continue to be eligible for the exception from withholding, entities that have been treated as QSLs will be required to enter into a QI agreement to satisfy and comply with the requirements for QDD treatment provided in the temporary regulations and in the updated QI Agreement. When these temporary regulations are finalized, the Treasury Department and the IRS expect the final regulations to supplant the proposed regulatory framework described in Notice 2010–46.

C. Certain Insurance Contracts

The 2013 proposed regulations do not specifically address whether payments made on life insurance or annuity contracts are dividend equivalents when the payments are directly or indirectly contingent upon or determined by reference to the payment of a dividend from sources within the United States. Comments noted that treating annuity contract payments as dividend equivalents could conflict with section 72, which provides that the holder of an annuity contract is taxed only when an amount is received from the annuity. Comments further noted that when a foreign person receives payments or withdrawals from an annuity contract issued by a domestic insurance company, the payment is FDAP subject to 30% withholding to the extent such payment or withdrawal constitutes gross income as determined in accordance with section 72. Similarly, withdrawals of income from a life insurance contract issued by a domestic insurance company are generally U.S. source FDAP subject to withholding. Commenters argued that the existing rules that apply to life insurance and annuity contracts obviate the need for withholding under section 871(m).

The Treasury Department and the IRS agree that the taxation of life insurance and annuity contracts issued by domestic insurance companies is adequately addressed under current law. Therefore, the temporary regulations provide that there is no dividend equivalent associated with a payment that a foreign person receives pursuant to the terms of an annuity, endowment, or life insurance contract issued by a domestic insurance company (including the foreign or U.S. possession branch of the domestic insurance company).

The Treasury Department and the IRS are considering how section 871(m) should apply to annuity, endowment, and life insurance contracts that reference U.S. equities and that are issued by foreign life insurance companies. Until further guidance is issued, the temporary regulations provide that these contracts do not include a dividend equivalent when issued by a foreign corporation that is predominately engaged in an insurance business and that would be subject to tax under subchapter L if it were a domestic corporation. Similarly, the temporary regulations do not treat any portion of a payment received by a foreign life insurance company as a dividend equivalent when the payment is made according to the terms of an insurance contract, such as reinsurance, by a foreign corporation meeting the same requirements. The Treasury Department and the IRS are also evaluating how section 871(m) should apply to reinsurance contracts. Taxpayers are encouraged to send comments on how section 871(m) should apply to foreign life insurance companies and the contracts they issue.

IV. Effective/Applicability Date

The final and temporary regulations are generally effective on September 18, 2015. To ensure that brokers have adequate time to develop the systems needed to implement the regulations, however, the final and temporary regulations generally apply to transactions issued on or after January 1, 2017. In addition, with respect to transactions issued on or after January 1, 2016, and before January 1, 2017, that are section 871(m) transactions, the regulations also apply to any payment of a dividend equivalent made on or after January 1, 2018. The regulations do not change the applicability date of § 1.871–15(d)(1)(i) for specified NPCs described in that section.

The chapter 4 regulations provide a coordinating effective date for the treatment of dividend equivalents as withholdable payments for purposes of chapter 4 withholding. Section 1.1471–2(b)(2)(i)(A)(*2*) provides that grandfathered obligations under chapter 4 include any obligation that gives rise to a withholdable payment solely because the obligation gives rise to a dividend equivalent pursuant to section 871(m) and the regulations thereunder. This grandfather rule applies only to obligations that are executed on or before the date that is six months after the date on which obligations of its type are first treated as giving rise to dividend equivalents.

Special Analyses

Certain IRS regulations, including this one, are exempt from the requirements of Executive Order 12866, as supplemented and reaffirmed by Executive Order 13563. Therefore, a regulatory impact assessment is not required. It also has been determined that section 553(b) of the Administrative Procedure Act (5 U.S.C. chapter 5) does not apply to these regulations. It is hereby certified that these regulations will not have a significant economic impact on a substantial number of small entities. This certification is based on the fact that few, if any, small entities will be affected by these regulations. The regulations will primarily affect multinational financial institutions, which tend to be larger businesses, and foreign entities. Therefore, a Regulatory Flexibility Analysis is not required. Pursuant to section 7805(f) of the Code, these regulations have been submitted to the Chief Counsel for Advocacy of the Small Business Administration for comment on its impact on small business.

Drafting Information

The principal authors of these regulations are D. Peter Merkel and Karen Walny of the Office of Associate Chief Counsel (International). Other personnel from the Treasury Department and the IRS also participated in the development of these regulations.

List of Subjects in 26 CFR Part 1

Income taxes, Reporting and recordkeeping requirements.

Adoption of Amendments to the Regulations

■ Accordingly, 26 CFR part 1 is amended as follows:

PART 1—INCOME TAXES

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

Authority: 26 U.S.C. 7805 * * *

§ 1.871–14(h) also issued under 26 U.S.C. 871(h) and 871(m). * * *

§§ 1.871–15 and 1.871–15T also issued under 26 U.S.C. 871(m). * * *

Par. 2. Section 1.871–14 is amended by:

■ 1. Redesignating paragraphs (h) and (i) as paragraphs (i) and (j), respectively.

■ 2. Adding new paragraphs (h) and (j)(3).

The additions read as follows:

§ 1.871–14 Rules relating to repeal of tax on interest of nonresident alien individuals and foreign corporations received from certain portfolio debt investments.

* * * * *

(h) *Portfolio interest not to include certain contingent interest*—(1) *Dividend equivalents.* Contingent interest does not qualify as portfolio interest to the extent that the interest is a dividend equivalent within the meaning of section 871(m).

(2) *Amount of dividend equivalent that is not portfolio interest.* The amount that does not qualify as portfolio interest because it is a dividend equivalent equals the amount of the dividend equivalent determined pursuant to § 1.871–15(j). Unless otherwise excluded pursuant to section 871(h), any other interest paid on an obligation that is not a dividend equivalent may qualify as portfolio interest.

* * * * *

(j) * * *

(3) *Effective/applicability date.* The rules of paragraph (h) of this section apply beginning September 18, 2015.

■ **Par. 3.** Section 1.871–15 is amended by:

■ 1. Redesignating paragraphs (d)(1)(i) as (d)(1)(i)(A), (d)(1) introductory text as (d)(1)(i), (d)(1)(ii) as (d)(1)(i)(B), (d)(1)(iii) as (d)(1)(i)(C), and (d)(1)(iv) as (d)(1)(i)(D).

■ 2. Removing ''2016'' from newly redesignated paragraph (d)(1)(i) and adding ''2017'' in its place.

■ 3. Removing ''Specified NPCs before January 1, 2016'' from newly redesignated paragraph (d)(1)(i) and adding ''*In general''* in its place.

■ 4. Adding new paragraphs (d)(1) introductory text, (d)(1)(ii) and (d)(2).

■ 5. Redesignating paragraph (o) as paragraph (r)(2) and:

■ a. Revising the heading for newly redesignated paragraph (r)(2),

■ b. Removing the language ''This'' in paragraph (r)(2) and adding ''Paragraph (d)(1)(i) of this'' in its place, and

■ c. Adding new paragraphs (r)(1), (r)(3) and (q).

■ 7. Adding new paragraphs (a) through (c), and (e) through (p).

The additions and revisions read as follows:

§ 1.871–15 Treatment of dividend equivalents.

(a) *Definitions.* For purposes of this section, the following terms have the meanings described in this paragraph (a).

(1) *Broker.* A *broker* is a broker within the meaning provided in section 6045(c).

(2) *Dealer.* A *dealer* is a dealer in securities within the meaning of section 475(c)(1).

(3) *Dividend.* A *dividend* is a dividend as described in section 316.

(4) *Equity-linked instrument.* An *equity-linked instrument* (*ELI*) is a financial transaction, other than a securities lending or sale-repurchase transaction or an NPC, that references the value of one or more underlying securities. For example, a futures contract, forward contract, option, debt instrument, or other contractual arrangement that references the value of one or more underlying securities is an ELI.

(5) *Initial hedge.* An *initial hedge* is the number of underlying security shares that a short party would need to fully hedge an NPC or ELI (whether the NPC or ELI is a complex contract or a simple contract benchmark (within the meaning of paragraph (h)(2) of this section), as appropriate) with respect to an underlying security at the time the NPC or ELI is issued, even if the short party does not in fact fully hedge the NPC or ELI.

(6) *Issue.* An NPC or ELI is treated as issued at inception, original issuance, or at the time of an issuance as a result of a deemed exchange pursuant to section 1001.

(7) *Notional principal contract.* A *notional principal contract* (*NPC*) is a notional principal contract as defined in § 1.446–3(c).

(8) *Option.* An *option* includes an option embedded in any debt instrument, forward contract, NPC, or other potential section 871(m) transaction.

(9) *Parties to the transaction*—(i) *Long party.* A *long party* is the party to a potential section 871(m) transaction with respect to an underlying security that would be entitled to receive a payment of a dividend equivalent (within the meaning of paragraph (i) of this section) described in paragraph (c) of this section.

(ii) *Short party.* A *short party* is the party to a potential section 871(m) transaction with respect to an underlying security that would be obligated to make a payment of a dividend equivalent (within the meaning of paragraph (i) of this section) described in paragraph (c) of this section.

(iii) *Party to the transaction.* A *party to the transaction* is any person that is a long party or a short party to a potential section 871(m) transaction, any agent acting on behalf of the long party or short party, or any person acting as an intermediary with respect to the potential section 871(m) transaction.

(iv) *Party to the transaction that is both a long party and a short party*—(A) *In general.* If a potential section 871(m) transaction references more than one underlying security, the long party and short party are determined separately with respect to each underlying security. A party to a potential section 871(m) transaction is both a long party and a short party when the party is entitled to a payment that references a dividend payment on an underlying security and the same party is obligated to make a payment that references a dividend payment on another underlying security pursuant to the potential section 871(m) transaction.

(B) *Example.* The following example illustrates the definitions in paragraph (a)(9) of this section:

Example. (i) Stock X and Stock Y are underlying securities. A and B enter into an NPC that entitles A to receive payments from B based on any appreciation in the value of Stock X and dividends paid on Stock X during the term of the contract and obligates A to make payments to B based on any depreciation in the value of Stock X during the term of the contract. In return, the NPC entitles B to receive payments from A based on any appreciation in the value of Stock Y and dividends paid on Stock Y during the term of the contract and obligates B to make payments to A based on any depreciation in the value of Stock Y during the term of the contract.

(ii) A is the long party with respect to Stock X, and the short party with respect to Stock Y. B is the long party with respect to Stock Y, and the short party with respect to Stock X.

(10) *Payment.* A *payment* has the meaning provided in paragraph (i) of this section.

(11) *Reference.* To *reference* means to be contingent upon or determined by reference to, directly or indirectly, whether in whole or in part.

(12) *Section 871(m) transaction and potential section 871(m) transaction.* A *section 871(m) transaction* is any securities lending or sale-repurchase transaction, specified NPC, or specified ELI. A *potential section 871(m) transaction* is any securities lending or sale-repurchase transaction, NPC, or ELI that references one or more underlying securities.

(13) *Securities lending or sale-repurchase transaction.* A *securities lending or sale-repurchase transaction* is any securities lending transaction, sale-repurchase transaction, or substantially similar transaction that references an underlying security. *Securities lending transaction* and *sale-repurchase transaction* have the same meaning as provided in § 1.861–3(a)(6).

(14) *Simple contracts and complex contracts*—(i) *Simple contract.* A *simple contract* is an NPC or ELI for which, with respect to each underlying security,

(A) All amounts to be paid or received on maturity, exercise, or any other payment determination date are calculated by reference to a single, fixed number of shares (as determined in paragraph (j)(3) of this section) of the underlying security, provided that the number of shares can be ascertained when the contract is issued, and (B) The contract has a single maturity or exercise date with respect to which all amounts (other than any upfront payment or any periodic payments) are required to be calculated with respect to the underlying security. A contract has a single exercise date even though it may be exercised by the holder at any time on or before the stated expiration of the contract. An NPC or ELI that includes a term that discontinuously increases or decreases the amount paid or received (such as a digital option), or that accelerates or extends the maturity is not a simple contract. A simple contract that is an NPC is a *simple NPC.* A simple contract that is an ELI is a *simple ELI.*

(ii) *Complex contract*—(A) *In general.* A *complex contract* is any NPC or ELI that is not a simple contract. A complex contract that is an NPC is a *complex NPC.* A complex contract that is an ELI is a *complex ELI.*

(B) Example. An ELI entitles the long party to a return equal to 200 percent of the appreciation on 100 shares of Stock X, and obligates the long party to pay an amount equal to the actual depreciation on 100 shares of Stock X. Because the ELI does not provide the long party with an amount that is calculated by reference to a single, fixed number of shares of Stock X on the maturity date that can be ascertained at issuance, it is not a simple ELI. More specifically, upon maturity the ELI will either entitle the long party to receive a payment that is, in substance, measured by reference to 200 shares of stock or obligate the long party to make a payment measured by reference to 100 shares of stock. The ELI is a complex ELI because it is not a simple ELI.

(15) *Underlying security.* An *underlying security* is any interest in an entity if a payment with respect to that interest could give rise to a U.S. source dividend pursuant to § 1.861–3, where applicable taking into account paragraph (m) of this section. Except as provided in paragraph (l) of this section, if a potential section 871(m) transaction references an interest in more than one entity described in the preceding sentence or different interests in the same entity, each referenced interest is a separate underlying security for purposes of applying the rules of this section.

(b) *Source of a dividend equivalent.* A dividend equivalent is treated as a dividend from sources within the United States for purposes of sections 871(a), 881, 892, 894, and 4948(a), and chapters 3 and 4 of subtitle A of the Internal Revenue Code.

(c) *Dividend equivalent*—(1) *In general.* Except as provided in paragraph (2), *dividend equivalent* means—

(i) Any payment that references the payment of a dividend from an underlying security pursuant to a securities lending or sale-repurchase transaction;

(ii) Any payment that references the payment of a dividend from an underlying security pursuant to a specified NPC described in paragraph (d) of this section;

(iii) Any payment that references the payment of a dividend from an underlying security pursuant to a specified ELI described in paragraph (e) of this section; and

(iv) Any other substantially similar payment as described in paragraph (f) of this section.

(2) *Exceptions*—(i) *Not a dividend.* A payment that references a distribution with respect to an underlying security is not a dividend equivalent to the extent that the distribution would not be subject to tax pursuant to section 871 or section 881 if the long party owned the underlying security. For example, if an NPC references stock in a regulated investment company that pays a dividend that includes a capital gains dividend described in section 852(b)(3)(C) that would not be subject to tax under section 871 or section 881 if paid directly to the long party, then an NPC payment is not a dividend equivalent to the extent that it is determined by reference to the capital gains dividend.

(ii) *Section 305 coordination.* A dividend equivalent with respect to a section 871(m) transaction is reduced by any amount treated in accordance with section 305(b) and (c) as a dividend with respect to the underlying security referenced by the section 871(m) transaction.

(iii) *Due bills.* A dividend equivalent does not include a payment made pursuant to a due bill arising from the actions of a securities exchange that apply to all transactions in the stock with respect to the dividend. For purposes of this section, a stock will be considered to trade with a due bill only when the relevant securities exchange has set an ex-dividend date with respect to a dividend that occurs after the record date.

(iv) *Certain payments pursuant to annuity, endowment, and life insurance contracts.* [Reserved]. For further guidance, see § 1.871–15T(c)(2)(iv).

(v) *Certain payments pursuant to employee compensation arrangements.* A dividend equivalent does not include the portion of equity-based compensation for personal services of a nonresident alien individual that is—

(A) Wages subject to withholding under section 3402 and the regulations under that section;

(B) Excluded from the definition of wages under § 31.3401(a)(6)–1; or

(C) Exempt from withholding under § 1.1441–4(b).

(d) *Specified NPCs*—(1) *Specified NPCs entered into before January 1, 2017*—(i) * * *.

(ii) *Specified NPC status as of January 1, 2017.* An NPC that is treated as a specified NPC pursuant to paragraph (d)(1)(i) of this section will remain a specified NPC on or after January 1, 2017.

(2) *Specified NPCs on or after January 1, 2017*—(i) *Simple NPCs.* A simple NPC that has a delta of 0.8 or greater with respect to an underlying security when the NPC is issued is a specified NPC.

(ii) *Complex NPCs.* A complex NPC that meets the substantial equivalence test described in paragraph (h) of this section with respect to an underlying security when the NPC is issued is a specified NPC.

(e) *Specified ELIs*—(1) *Simple ELIs.* A simple ELI that has a delta of 0.8 or greater with respect to an underlying security when the ELI is issued is a specified ELI.

(2) *Complex ELIs.* A complex ELI that meets the substantial equivalence test described in paragraph (h) of this section with respect to an underlying security when the ELI is issued is a specified ELI.

(f) *Other substantially similar payments.* For purposes of this section, any payment made in satisfaction of a tax liability of the long party with respect to a dividend equivalent by a withholding agent is a dividend equivalent received by the long party. The amount of that dividend equivalent constitutes additional income to the payee to the extent provided in § 1.1441–3(f)(1).

(g) *Delta*—(1) *In general.* Delta is the ratio of the change in the fair market value of an NPC or ELI to a small change in the fair market value of the number of shares of the underlying security (as determined under paragraph (j)(3) of this section) referenced by the NPC or ELI. If an NPC or ELI contains more than one reference to a single underlying security, all references to that underlying security are taken into account in determining the delta with respect to that underlying security. If an NPC or ELI references more than one underlying security or other property, the delta with respect to each underlying security must be determined without taking into account any other underlying security or property. The delta of an equity derivative that is embedded in a debt instrument or other derivative is determined without taking into account changes in the market value of the debt instrument or other derivative that are not directly related to the equity element of the instrument. Thus, for example, the delta of an option embedded in a convertible note is determined without regard to the debt component of the convertible note. For purposes of this section, delta must be determined in a commercially reasonable manner. If a taxpayer calculates delta for non-tax business purposes, that delta ordinarily is the delta used for purposes of this section.

(2) *Time for determining delta.* For purposes of applying the rules of this section, the delta of a potential section 871(m) transaction is determined only when the potential section 871(m) transaction is issued (as defined in paragraph (a)(6) of this section).

(3) *Simplified delta calculation for certain simple contracts that reference multiple underlying securities.* If an NPC or ELI references 10 or more underlying securities and the short party uses an exchange-traded security (for example, an exchange-traded fund) that references substantially all of the underlying securities (the hedge security) to hedge the NPC or ELI at the time it is issued, the delta of the NPC or ELI may be calculated by determining the ratio of the change in the fair market value of the simple contract to a small change in the fair market value of the hedge security. A delta determined under this paragraph (g)(3) must be used as the delta for each underlying security for purposes of calculating the amount of a dividend equivalent as provided in paragraph (j)(1)(ii) of this section.

(4) *Examples.* The following examples illustrate the rules of this paragraph (g). For purposes of these examples, Stock X and Stock Y are common stock of domestic corporations X and Y. LP is the long party to the transaction.

Example 1. Delta calculation for an NPC. The terms of an NPC require LP to pay the short party an amount equal to all of the depreciation in the value of 100 shares of Stock X and an interest-rate based return. In return, the NPC requires the short party to pay LP an amount equal to all of the appreciation in the value of 100 shares of Stock X and any dividends paid by X on those shares. The value of the NPC will change by $1 for each $0.01 change in the price of a share of Stock X. When LP entered into the NPC, Stock X had a fair market value of $50 per share. The NPC therefore has a delta of 1.0 ($1.00/($0.01 × 100)).

Example 2. Delta calculation for an option. LP purchases a call option that references 100 shares of Stock Y. At the time LP purchases the call option, the value of the option is expected to change by $0.30 for a $0.01 change in the price of a share of Stock Y. When LP purchases the option, Stock Y has a fair market value of $100 per share. The call option has a delta of 0.3 ($0.30/($0.01 × 100)).

(h) *Substantial Equivalence.* [Reserved]. For further guidance, see § 1.871–15T(h).

(i) *Payment of a dividend equivalent*—(1) *Payments determined on gross basis.* For purposes of this section, a payment includes any gross amount that references the payment of a dividend and that is used in computing any net amount transferred to or from the long party even if the long party makes a net payment to the short party or no amount is paid because the net amount is zero.

(2) *Actual and estimated dividends*—(i) *In general.* A payment includes any amount that references an actual or estimated payment of dividends, whether the reference is explicit or implicit. If a potential section 871(m) transaction provides for a payment based on an estimated dividend that adjusts to account for the amount of an actual dividend paid, the payment is treated as referencing the actual dividend amount and not an estimated dividend amount.

(ii) *Implicit dividends.* A payment includes an actual or estimated dividend payment that is implicitly taken into account in computing one or more of the terms of a potential section 871(m) transaction, including interest rate, notional amount, purchase price, premium, upfront payment, strike price, or any other amount paid or received pursuant to the potential section 871(m) transaction.

(iii) *Actual dividend presumption.* A short party to a section 871(m) transaction is treated as paying a per-share dividend amount equal to the actual dividend amount unless the short party to the section 871(m) transaction identifies a reasonable estimated dividend amount in writing at the time the transaction is issued. For this purpose, a reasonable estimated dividend amount stated in an offering document or the documents governing the terms at the time the transaction is issued will establish the estimated dividend amount. To qualify as an estimated dividend amount, the written estimated dividend amount must separately state the amount estimated for each anticipated dividend or state a formula that allows each dividend to be determined. If an underlying security is not expected to pay a dividend, a reasonable estimate of the dividend amount may be zero.

(iv) *Additions to estimated payments.* If a section 871(m) transaction provides for any payment in addition to an estimated dividend and that additional payment is determined by reference to a dividend (for example, a special dividend), both the estimated dividend and the additional payment are used to determine the per-share dividend amount.

(3) *Dividends for certain baskets*—(i) *In general.* If a section 871(m) transaction references long positions in more than 25 underlying securities, the short party may treat the dividends with respect to the referenced underlying securities as paid at the end of the applicable calendar quarter to compute the per-share dividend amount.

(ii) *Publicly available dividend yield.* For purposes of paragraph (i)(3)(i) of this section, if a section 871(m) transaction references the same underlying securities as a security (for example, stock in an exchange-traded fund) or index for which there is a publicly available quarterly dividend yield, the publicly available dividend yield may be used to determine the per-share dividend amount for the section 871(m) transaction with any adjustment for special dividends.

(iii) *Dividend yield for a section 871(m) transaction using the simplified delta calculation.* When the delta of a section 871(m) transaction is determined under paragraph (g)(3) of this section, the per-share dividend amount for that section 871(m) transaction must be determined using the dividend yield for the exchange-traded security that fully hedges the section 871(m) transaction.

(4) *Examples.* The following examples illustrate the rules of this paragraph (i). For purposes of these examples, Stock X is common stock of Corporation X, a domestic corporation, that historically pays quarterly dividends on Stock X.

The parties anticipate that Corporation X will continue to pay quarterly dividends.

Example 1. Forward contract to purchase domestic stock. (i) When Stock X is trading at $50 per share, Foreign Investor enters into a forward contract to purchase 100 shares of Stock X in one year. Reasonable estimates of the quarterly dividend are specified in the transaction documents. The price in the forward contract is determined by multiplying the number of shares referenced in the contract by the current price of the shares and an interest rate, and subtracting the value of any dividends expected to be paid during the term of the contract. Assuming that the forward contract is priced using an interest rate of 4 percent and total estimated dividends with a future value of $1 per share during the term of the forward contract, the purchase price set in the forward contract is $5,100 (100 shares × $50 per share × 1.04 − ($1 × 100)).

(ii) Subject to paragraph (i)(2)(iv) of this section, the estimated dividend amount is the per-share dividend amount because the estimate is reasonable and specified in accordance with paragraph (i)(2)(iii) of this section. The estimated per-share dividend amount is a dividend equivalent for purposes of this section.

Example 2. Price return only swap contract. (i) Foreign Investor enters into a price return swap contract that entitles Foreign Investor to receive payments based on the appreciation in the value of 100 shares of Stock X and requires Foreign Investor to pay an amount based on LIBOR plus any depreciation in the value of Stock X. The swap contract neither explicitly entitles Foreign Investor to payments based on dividends paid on Stock X during the term of the contract nor references an estimated dividend amount. The LIBOR rate in the swap contract, however, is reduced to reflect expected annual dividends on Stock X.

(ii) Because the LIBOR leg of the swap contract is reduced to reflect estimated dividends and the estimated dividend amount is not specified, Foreign Investor is treated as receiving the actual dividend amount in accordance with paragraph (i)(2) of this section. The actual per-share dividend amounts are dividend equivalents for purposes of this section.

(j) *Amount of dividend equivalent*—(1) *Calculation of the amount of a dividend equivalent*—(i) *Securities lending or sale-repurchase transactions.* For a securities lending or sale-repurchase transaction, the amount of the dividend equivalent for each underlying security equals the amount of the actual per-share dividend paid on the underlying security multiplied by the number of shares of the underlying security.

(ii) *Simple contracts.* For a simple contract that is a section 871(m) transaction, the amount of the dividend equivalent for each underlying security equals:

(A) The per-share dividend amount (as determined under either paragraph (i)(2) or (i)(3) of this section) with respect to the underlying security multiplied by;

(B) The number of shares of the underlying security multiplied by;

(C) The delta of the section 871(m) transaction with respect to the underlying security.

(iii) *Complex contracts.* For a complex contract that is a section 871(m) transaction, the amount of the dividend equivalent for each underlying security equals:

(A) The per-share dividend amount (as determined under paragraph (i)(2) or (i)(3) of this section) with respect to the underlying security multiplied by;

(B) The initial hedge for the underlying security.

(iv) *Other substantially similar payments.* In addition to any amount determined pursuant to paragraph (j)(1)(i), (ii), or (iii), the amount of a dividend equivalent includes the amount of any payment described in paragraph (f) of this section.

(2) *Time for determining the amount of a dividend equivalent.* The amount of a dividend equivalent is determined on the earlier of the date that is the record date of the dividend and the day prior to the ex-dividend date with respect to the dividend. For example, if a specified NPC provides for a payment at settlement that takes into account an earlier dividend payment, the amount of the dividend equivalent is determined on the earlier of the record date or the day prior to the ex-dividend date for that dividend.

(3) *Number of shares.* The number of shares of an underlying security generally is the number of shares of the underlying security stated in the contract. If the transaction modifies that number by a factor or fraction or otherwise alters the amount of any payment, the number of shares is adjusted to take into account the factor, fraction, or other modification. For example, in a transaction in which the long party receives or makes payments based on 200 percent of the appreciation or depreciation (as applicable) of 100 shares of stock, the number of shares of the underlying security is 200 shares of the stock.

(k) *Limitation on the treatment of certain corporate acquisitions as section 871(m) transactions.* A potential section 871(m) transaction is not a section 871(m) transaction with respect to an underlying security if the transaction obligates the long party to acquire ownership of the underlying security as part of a plan pursuant to which one or more persons (including the long party) are obligated to acquire underlying securities representing more than 50 percent of the value of the entity issuing the underlying securities.

(l) *Rules relating to indices*—(1) *Purpose.* The purpose of this section is to provide a safe harbor for potential section 871(m) transactions that reference certain passive indices that are based on a diverse basket of publicly-traded securities and that are widely used by numerous market participants. Notwithstanding any other provision in this paragraph (l), an index is not a qualified index if treating the index as a qualified index would be contrary to the purpose described in this paragraph.

(2) *Qualified index not treated as an underlying security.* For purposes of this section, a qualified index is treated as a single security that is not an underlying security. The determination of whether an index referenced in a potential section 871(m) transaction is a qualified index is made at the time the transaction is issued based on whether the index is a qualified index on the first business day of the calendar year in which the transaction is issued.

(3) *Qualified index.* A *qualified index* means an index that—

(i) References 25 or more component securities (whether or not the security is an underlying security);

(ii) Except as provided in paragraph (l)(6)(ii) of this section, references only long positions in component securities;

(iii) References no component underlying security that represents more than 15 percent of the weighting of the component securities in the index;

(iv) References no five or fewer component underlying securities that together represent more than 40 percent of the weighting of the component securities in the index;

(v) Is modified or rebalanced only according to publicly stated, predefined criteria, which may require interpretation by the index provider or a board or committee responsible for maintaining the index;

(vi) Did not provide an annual dividend yield in the immediately preceding calendar year from component underlying securities that is greater than 1.5 times the annual dividend yield of the S&P 500 Index as reported for the immediately preceding calendar year; and

(vii) Is traded through futures contracts or option contracts (regardless of whether the contracts provide price only or total return exposure to the index or provide for dividend reinvestment in the index) on—

(A) A national securities exchange that is registered with the Securities and Exchange Commission or a domestic board of trade designated as a contract market by the Commodity Futures Trading Commission; or

(B) A foreign exchange or board of trade that is a qualified board or exchange as determined by the Secretary pursuant to section 1256(g)(7)(C) or that has a staff no action letter from the CFTC permitting direct access from the United States that is effective on the applicable testing date, provided that the referenced component underlying securities, in the aggregate, comprise less than 50 percent of the weighting of the component securities in the index.

(4) *Safe harbor for certain indices that reference assets other than underlying securities.* Notwithstanding paragraph (l)(3) of this section, an index is a qualified index if the referenced component underlying securities in the aggregate comprise 10 percent or less of the weighting of the component securities in the index.

(5) *Weighting of component securities.* For purposes of this paragraph (l), the weighting of a component security of an index is the percentage of the index's value represented, or accounted for, by the component security.

(6) *Transactions that reference a qualified index and one or more component securities or indices*—(i) *In general.* When a potential section 871(m) transaction references a qualified index and one or more component securities or other indices, the qualified index remains a qualified index only if the potential section 871(m) transaction does not reference a short position in any referenced component security of the qualified index, other than a short position with respect to the entire qualified index (for example, a cap or floor) or a de minimis short position described in paragraph (l)(6)(ii) of this section. If, in connection with a potential section 871(m) transaction that references a qualified index, a taxpayer (or a related person within the meaning of section 267(b) or section 707(b)) enters into one or more transactions that reduce exposure to any referenced component security of the index, other than transactions that reduce exposure to the entire index, then the potential section 871(m) transaction is not treated as referencing a qualified index.

(ii) *Safe harbor for de minimis short positions.* Notwithstanding paragraphs (l)(3)(ii) and (l)(6)(i) of this section, an index may be a qualified index if the short position (whether part of the index or entered into separately by the taxpayer or related person within the meaning of section 267(b) or section 707(b)) reduces exposure to referenced component securities of a qualified index (excluding any short positions with respect to the entire qualified index) by five percent or less of the value of the long positions in component securities in the qualified index.

(7) *Transactions that indirectly reference a qualified index.* If a potential section 871(m) transaction references a security (for example, stock in an exchange-traded fund) that tracks a qualified index, the potential section 871(m) transaction will be treated as referencing a qualified index.

(m) *Rules relating to derivatives that reference partnerships*—(1) *In general.* When a potential section 871(m) transaction references a partnership interest, the assets of the partnership will be treated as referenced by the potential section 871(m) transaction only if the partnership carries on a trade or business of dealing or trading in securities, holds significant investments in securities (either of which is a covered partnership), or directly or indirectly holds an interest in a lower-tier partnership that is a covered partnership. For purposes of this section, if a covered partnership directly or indirectly holds assets that are underlying securities or potential section 871(m) transactions, any potential section 871(m) transaction that references an interest in the covered partnership is treated as referencing the shares of the underlying securities, including underlying securities of potential section 871(m) transactions, directly or indirectly allocable to that partnership interest. For purposes of this paragraph (m), a security is defined in section 475(c).

(2) *Significant investments in securities*—(i) *In general.* For purposes of this paragraph (m), a partnership holds significant investments in securities if either—

(A) 25 percent or more of the value of the partnership's assets consist of underlying securities or potential section 871(m) transactions; or

(B) The value of the underlying securities or potential section 871(m) transactions equals or exceeds $25 million.

(ii) *Determining the value of the partnership's assets.* For purposes of this paragraph (m)(2), the value of a partnership's assets is determined at the time the potential 871(m) transaction referencing that partnership interest is issued based on the value of the assets held by the partnership on the last day of the partnership's prior taxable year unless the long party or the short party has actual knowledge that a subsequent transaction has caused the partnership to cross either of the thresholds described in paragraph (m)(2)(i). The value of a partnership's assets is equal to their fair market value, except that the value of any NPC, futures contract, forward contract, option, and any similar financial instrument held by the partnership is deemed to be the value of the notional securities referenced by the transaction.

(n) *Combined transactions*—(1) *In general.* For purposes of determining whether a potential section 871(m) transaction is a section 871(m) transaction, two or more potential section 871(m) transactions are treated as a single transaction with respect to an underlying security when—

(i) A person (or a related person within the meaning of section 267(b) or section 707(b)) is the long party with respect to the underlying security for each potential section 871(m) transaction;

(ii) The potential section 871(m) transactions reference the same underlying security;

(iii) The potential section 871(m) transactions, when combined, replicate the economics of a transaction that would be a section 871(m) transaction if the transactions had been entered into as a single transaction; and

(iv) The potential section 871(m) transactions are entered into in connection with each other (regardless of whether the transactions are entered into simultaneously or with the same counterparty).

(2) *Section 871(m) transactions.* If a potential section 871(m) transaction is a section 871(m) transaction, either by itself or as a result of a combination with one or more other potential section 871(m) transactions, it does not cease to be a section 871(m) transaction as a result of applying paragraph (n) of this section or disposing of one or more of the potential section 871(m) transaction with which it is combined.

(3) *Short party presumptions regarding combined transactions*—(i) *Transactions in separate accounts.* A short party that is a broker may presume that transactions are not entered into in connection with each other for purposes of paragraph (n)(1) of this section if a long party holds or reflects the transactions in separate accounts maintained by the short party, unless the short party has actual knowledge that the transactions held or reflected in separate accounts by the long party were entered into in connection with each other or that separate accounts were created or used to avoid section 871(m).

(ii) *Transactions separated by at least two business days.* A short party that is a broker may presume that transactions entered into two or more business days apart are not entered into in connection with each other for purposes of paragraph (n)(1) of this section unless the short party has actual knowledge that the transactions were entered into in connection with each other.

(4) *Presumptions Commissioner will apply to long party*—(i) *Transactions in separate trading books.* The Commissioner will presume that a long party did not enter into two or more transactions in connection with each other for purposes of paragraph (n)(1) of this section if the long party properly reflected those transactions on separate trading books. The Commissioner may rebut this presumption with facts and circumstances showing that transactions reflected on separate trading books were entered into in connection with each other or that separate trading books were created or used to avoid section 871(m).

(ii) *Transactions separated by at least two days.* The Commissioner will presume that a long party did not enter into two or more transactions in connection with each other for purposes of paragraph (n)(1) of this section if the long party entered into the transactions two or more business days apart. The Commissioner may rebut this presumption with facts and circumstances showing that the transactions entered into two or more business days apart were entered into in connection with each other.

(iii) *Transactions separated by less than two days and reflected in the same trading book.* The Commissioner will presume that transactions that are entered into less than two business days apart and reflected on the same trading book are entered into in connection with each other. A long party can rebut this presumption with facts and circumstances showing that the transactions were not entered into in connection with each other.

(5) *Rules of application*—(i) *Two business days rule.* For the purpose of determining the number of business days between transactions, the short party may, and the Commissioner will, assume that all transactions are entered into at 4:00 p.m. on the date the transaction becomes effective in the jurisdiction of the long party.

(ii) *No long party presumptions.* Notwithstanding the presumptions described in paragraphs (n)(3) and (n)(4) of this section, the long party must treat two or more transactions as combined transactions if the transactions are described in paragraph (n)(1) of section.

(6) *Ordering rule for transactions entered into in connection with each other.* If a long party enters into more than two potential section 871(m) transactions that could be combined under this paragraph (n), a short party is required to apply paragraph (n)(1) of this section by combining transactions in a manner that results in the most transactions with a delta of 0.8 or higher with respect to the referenced underlying security. Thus, for example, if a taxpayer has sold one at-the-money put and purchased two at-the-money calls, each with respect to 100 shares of the same underlying security, the put and one call are combined. Similarly, a purchased call on 100 shares and a sold put on 200 shares of the same underlying security can be combined for 100 shares with 100 shares of the put remaining separate. The two calls are not combined because they do not provide the long party with economic exposure to depreciation in the underlying security. Similarly, if a long party enters into more than two potential section 871(m) transactions that could be combined under this paragraph (n), but have not been combined by a short party, the long party is required to apply paragraph (n)(1) of this section by combining transactions in a manner that results in the most transactions with a delta of 0.8 or higher with respect to the referenced underlying security.

(7) *More than one underlying security referenced.* If potential section 871(m) transactions reference more than one underlying security, paragraph (n)(1) of this section applies separately with respect to each underlying security.

(o) *Anti-abuse rule.* If a taxpayer (directly or through the use of a related person within the meaning of section 267(b) or section 707(b)) acquires (whether by entering into, purchasing, accepting by transfer, by exchange, or by conversion, or otherwise acquiring) or disposes of (whether by sale, offset, exercise, termination, expiration, maturity, or other means) a transaction or transactions with a principal purpose of avoiding the application of this section, the Commissioner may treat any payment (as described in paragraph (i) of this section) made with respect to that transaction or transactions as a dividend equivalent to the extent necessary to prevent the avoidance of this section. Therefore, notwithstanding any other provision of this section, the Commissioner may, for example, adjust the delta of a transaction, change the number of shares, adjust an estimated dividend amount, change the maturity, adjust the timing of payments, treat a transaction that references a partnership interest as referencing the assets of the partnership, combine, separate, or disregard transactions, indices, or components of indices to reflect the substance of the transaction or transactions, or otherwise depart from the rules of this section as necessary to determine whether the transaction includes a dividend equivalent or the amount or timing of a dividend equivalent. A purpose may be a principal purpose even though it is outweighed by other purposes (taken together or separately). When a withholding agent knows that the taxpayer acquired or disposed of a transaction or transactions with a principal purpose of avoiding the application of this section and the Commissioner treats a payment made with respect to any transaction as a dividend equivalent, the withholding agent may be liable for any tax pursuant to section 1461.

(p) *Information required to be reported regarding a potential section 871(m) transaction*—(1) *In general.* If a broker or dealer is a party to a potential section 871(m) transaction with a counterparty or customer that is not a broker or dealer, the broker or dealer is required to determine whether the potential section 871(m) transaction is a section 871(m) transaction. If both parties to a potential section 871(m) transaction are brokers or dealers, or neither party to a potential section 871(m) transaction is a broker or dealer, the short party must determine whether the potential section 871(m) transaction is a section 871(m) transaction. The party to the transaction that is required to determine whether a transaction is a section 871(m) transaction must also determine and report to the counterparty or customer the timing and amount of any dividend equivalent (as described in paragraphs (i) and (j) of this section). Except as otherwise provided in paragraph (n)(3) of this section, the party required to make the determinations described in this paragraph is required to exercise reasonable diligence to determine whether a transaction is a section 871(m) transaction, the amount of any dividend equivalents, and any other information necessary to apply the rules of this section. The information must be provided in the manner prescribed in paragraphs (p)(2) and (p)(3) of this section. The determinations required by paragraph (p) of this section are binding on the parties to the potential section 871(m) transaction and on any person who is a withholding agent with respect to the potential section 871(m) transaction unless the person knows or has reason to know that the information received is incorrect. The determinations are not binding on the Commissioner.

(2) *Reporting requirements.* For rules regarding the reporting requirements of withholding agents with respect to dividend equivalents described in this section, see §§ 1.1461–1(b) and (c) and 1.1474–1(c) and (d).

(3) *Additional information available to a party to a potential section 871(m) transaction*—(i) *In general.* Upon request by any person described in paragraph (p)(3)(ii) of this section, the party required to report information pursuant to paragraph (p)(1) of this section must provide the requester with information regarding the amount of each dividend equivalent, the delta of the potential section 871(m) transaction, the amount of any tax withheld and deposited, the estimated dividend amount if specified in accordance with paragraph (i)(2)(iii) of this section, the identity of any transactions combined pursuant to paragraph (n) of this section, and any other information necessary to apply the rules of this section. The information requested must be provided within a reasonable time, not to exceed 10 business days, and communicated in one or more of the following ways:

(A) By telephone, and confirmed in writing;

(B) By written statement sent by first class mail to the address provided by the requesting party;

(C) By electronic publication available to all persons entitled to request information; or

(D) By any other method agreed to by the parties, and confirmed in writing.

(ii) *Persons entitled to request information.* Any party to the transaction described in paragraph (a)(9) of this section may request the information specified in paragraph (p) of this section with respect to a potential section 871(m) transaction from the party required by paragraph (p)(3)(i) of this section to provide the information.

(iii) *Reliance on information received.* A person described in paragraph (p)(1) or (p)(3)(ii) of this section that receives information described in paragraph (p)(1) or (p)(3)(i) of this section may rely on that information to provide information to any other person unless the recipient knows or has reason to know that the information received is incorrect. When the recipient knows or has reason to know that the information received is incorrect, the recipient must make a reasonable effort to determine and provide the information described in paragraph (p)(1) or (p)(3)(i) of this section to any person described in paragraph (p)(1) or (p)(3)(ii) of this section that requests information from the recipient.

(4) *Recordkeeping rules*—(i) *In general.* For rules regarding recordkeeping requirements sufficient to establish whether a transaction is a section 871(m) transaction and whether a payment is a dividend equivalent and the amount of gross income treated as a dividend equivalent, see § 1.6001–1.

(ii) *Records sufficient to establish whether a transaction is a section 871(m) transaction and any dividend equivalent amount.* Any person required to retain records must keep sufficient information to establish whether a transaction is a section 871(m) transaction and the amount of a dividend equivalent (if any), including documentation and work papers supporting the delta calculation or the substantial equivalence test (including the number of shares of the initial hedge), as applicable, and written estimated dividends (if any). The records and documentation must be created substantially contemporaneously. A record will be considered to have been created substantially contemporaneously if it was created within 10 business days of the date the potential section 871(m) transaction is issued.

(q) *Dividend and dividend equivalent payments to a qualified derivatives dealer.* [Reserved]. For further guidance, see § 1.871–15T(q).

(r) *Effective/applicability date*—(1) *In general.* This section applies to payments made on or after September 18, 2015 except as provided in paragraphs (r)(2) and (3) of this section.

(2) *Effective/applicability date for paragraph (d)(1)(i).* * * *

(3) *Effective/applicability date for paragraphs (d)(2) and (e).* Paragraphs (d)(2) and (e) apply to any payment made on or after January 1, 2017, with respect to any transaction issued on or after January 1, 2017, and to any payment made on or after January 1, 2018, with respect to any transaction issued on or after January 1, 2016, and before January 1, 2017.

■ **Par. 4.** Section 1.871–15T is added to read as follows:

§ 1.871–15T Treatment of dividend equivalents (temporary).

(a) through (b) [Reserved]. For further guidance, see § 1.871–15(a) through (b).

(c) [Reserved]. For further guidance, see § 1.871–15(c)(1) through (c)(2)(iii).

(iv) *Payments made pursuant to annuity, endowment, and life insurance contracts*—(A) *Insurance contracts issued by domestic insurance companies.* A payment made pursuant to a contract that is an annuity, endowment, or life insurance contract issued by a domestic corporation (including its foreign or U.S. possession branch) that is a life insurance company described in section 816(a) does not include a dividend equivalent if the payment is subject to tax under section 871(a) or section 881.

(B) *Insurance contracts issued by foreign insurance companies.* A payment does not include a dividend equivalent if it is made pursuant to a contract that is an annuity, endowment, or life insurance contract issued by a foreign corporation that is predominantly engaged in an insurance business and that would be subject to tax under subchapter L if it were a domestic corporation.

(C) *Insurance contracts held by foreign insurance companies.* A payment made pursuant to a policy of insurance (including a policy of reinsurance) does not include a dividend equivalent if it is made to a foreign corporation that is predominantly engaged in an insurance business and that would be subject to tax under subchapter L if it were a domestic corporation.

(v) [Reserved]. For further guidance, see § 1.871–15(c)(2)(v).

(d) through (g) [Reserved]. For further guidance, see § 1.871–15(d) through (g).

(h) *Substantial equivalence test*—(1) *In general.* The substantial equivalence test described in this paragraph (h) applies to determine whether a complex contract is a section 871(m) transaction. The substantial equivalence test assesses whether a complex contract substantially replicates the economic performance of the underlying security by comparing, at various testing prices for the underlying security, the differences between the expected changes in value of that complex contract and its initial hedge with the differences between the expected changes in value of a simple contract benchmark (as described in paragraph (h)(2) of this section) and its initial hedge. If the complex contract contains more than one reference to a single underlying security, all references to that underlying security are taken into account for purposes of applying the substantial equivalence test with respect to that underlying security. With respect to an equity derivative that is embedded in a debt instrument or other derivative, the substantial equivalence test is applied to the complex contract without taking into account changes in the market value of the debt instrument or other derivative that are not directly related to the equity element of the instrument. The complex contract is a section 871(m) transaction with respect to an underlying security if, for that underlying security, the expected change in value of the complex contract and its initial hedge is equal to or less than the expected change in value of the simple contract benchmark and its initial hedge when the substantial equivalence test described in this paragraph (h) is calculated at the time the complex contract is issued. To the extent that the steps of the substantial equivalence test set out in this paragraph (h) cannot be applied to a particular complex contract, a taxpayer must use the principles of the substantial equivalence test to reasonably determine whether the complex contract is a section 871(m) transaction with respect to each underlying security. For purposes of this section, the test must be applied and the inputs must be determined in a commercially reasonable manner. If a taxpayer calculates any relevant input for non-tax business purposes, that input ordinarily is the input used for purposes of this section.

(2) *Simple contract benchmark.* The simple contract benchmark is a closely comparable simple contract that, at the time the complex contract is issued, has a delta of 0.8, references the applicable underlying security referenced by the complex contract, and has the same maturity as the complex contract with respect to the applicable underlying security. Depending on the complex contract, the simple contract benchmark might be, for example, a call option, a put option, or a collar.

(3) *Substantial equivalence.* A complex contract is a section 871(m) transaction with respect to an underlying security if the complex contract calculation described in paragraph (h)(4) of this section results in an amount that is equal to or less than the amount of the benchmark calculation described in paragraph (h)(5) of this section.

(4) *Complex contract calculation*—(i) *In general.* The complex contract calculation for each underlying security referenced by a potential section 871(m) transaction that is a complex contract is computed by:

(A) Determining the change in value (as described in paragraph (h)(4)(ii) of this section) of the complex contract with respect to the underlying security at each testing price (as described in paragraph (h)(4)(iii) of this section);

(B) Determining the change in value of the initial hedge for the complex contract at each testing price;

(C) Determining the absolute value of the difference between the change in value of the complex contract determined in paragraph (h)(4)(i)(A) of this section and the change in value of the initial hedge determined in paragraph (h)(4)(i)(B) of this section at each testing price;

(D) Determining the probability (as described in paragraph (h)(4)(iv) of this section) associated with each testing price;

(E) Multiplying the absolute value for each testing price determined in paragraph (h)(4)(i)(C) of this section by the corresponding probability for that testing price determined in paragraph (h)(4)(i)(D) of this section;

(F) Adding the product of each calculation determined in paragraph (h)(4)(i)(E) of this section; and

(G) Dividing the sum determined in paragraph (h)(4)(i)(F) of this section by the initial hedge for the complex contract.

(ii) *Determining the change in value.* The change in value of a complex contract is the difference between the value of the complex contract with respect to the underlying security at the time the complex contract is issued and the value of the complex contract with respect to the underlying security if the price of the underlying security were equal to the testing price at the time the complex contract is issued. The change in value of the initial hedge of a complex contract with respect to the underlying security is the difference between the value of the initial hedge at the time the complex contract is issued and the value of the initial hedge if the price of the underlying security were equal to the testing price at the time the complex contract is issued.

(iii) *Testing price.* The testing prices must include the prices of the underlying security if the price of the underlying security at the time the complex contract is issued were alternatively increased by one standard deviation and decreased by one standard deviation, each of which is a separate testing price. In circumstances where using only two testing prices is reasonably likely to provide an inaccurate measure of substantial equivalence, a taxpayer must use additional testing prices as necessary to determine whether a complex contract satisfies the substantial equivalence test. If additional testing prices are used for the substantial equivalence test, the probabilities as described in paragraph (h)(4)(iv) of this section must be adjusted accordingly.

(iv) *Probability.* For purposes of paragraphs (h)(4)(i)(D) and (E) of this section, the probability of an increase by one standard deviation is the measure of the likelihood that the price of the underlying security will increase by any amount from its price at the time the complex contract is issued. For purposes of paragraphs (h)(4)(i)(D) and (E) of this section, the probability of a decrease by one standard deviation is the measure of the likelihood that the price of the underlying security will decrease by any amount from its price at the time the complex contract is issued.

(5) *Benchmark calculation.* The benchmark calculation with respect to each underlying security referenced by the potential section 871(m) transaction is determined by using the computation methodology described in paragraph (h)(4) of this section with respect to a simple contract benchmark for the underlying security.

(6) *Substantial equivalence calculation for certain complex contracts that reference multiple underlying securities.* If a complex contract references 10 or more underlying securities and the short party uses an exchange-traded security (for example, an exchange-traded fund) that references substantially all of the underlying securities (the hedge security) to hedge the complex contract at the time it is issued, the substantial equivalence calculations for the complex contract may be calculated by treating the hedge security as the underlying security. When the hedge security is used for the substantial equivalence calculation pursuant to this paragraph (h)(6), the initial hedge is the number of shares of the hedge security for purposes of calculating the amount of a dividend equivalent as provided in paragraph (j)(1)(iii) of this section.

(7) *Example.* The following example illustrates the rules of paragraph (h) of this section. For purposes of this example, Stock X is common stock of domestic corporation X. FI is the financial institution that structures the transaction described in the example, and is the short party to the transaction. Investor is a nonresident alien individual.

Example. Complex contract that is not substantially equivalent. (i) FI issues an investment contract (the Contract) that has a stated maturity of one year, and Investor purchases the Contract from FI at issuance for $10,000. At maturity, the Contract entitles Investor to a return of $10,000 (i) plus 200 percent of any appreciation in Stock X above $100 per share, capped at $110, on 100 shares or (ii) minus 100 percent of any depreciation in Stock X below $90 on 100 shares. At the time FI issues the Contract, the price of Stock X is $100 per share. Thus, for example, Investor will receive $11,000 if the price of Stock X is $105 per share at maturity of the Contract, but Investor will receive $9,000 if the price of Stock X is $80 per share when the Contract matures. At issuance, FI acquires 64 shares of Stock X to fully hedge the Contract issued to Investor.

(ii) The Contract references an underlying security and is not an NPC, so it is classified as an ELI under paragraph (a)(4) of this section. At issuance, the Contract does not provide for an amount paid at maturity that is calculated by reference to a single, fixed number of shares of Stock X. When the Contract matures, the amount paid is effectively calculated based on either 200 shares of Stock X (if the price of Stock X has appreciated up to $110) or 100 shares of Stock X (if the price of Stock X has declined below $90). Consequently, the Contract is a complex contract described in paragraph (a)(14) of this section.

(iii) Because it is a complex ELI, FI applies the substantial equivalence test described in paragraph (h) of this section to determine whether the Contract is a specified ELI. FI determines that the price of Stock X would be $120 if the price of Stock X were increased by one standard deviation, and $79 if the price of Stock X were decreased by one standard deviation. Based on these results, FI next determines the change in value of the Contract to be $2,000 at the testing price that represents an increase by one standard deviation ($12,000 testing price minus $10,000 issue price) and a negative $1,100 at the testing price that represents a decrease by one standard deviation ($10,000 issue price minus $8,900 testing price). FI performs the same calculations for the 64 shares of Stock X that constitute the initial hedge, determining that the change in value of the initial hedge is $1,280 at the testing price that represents an increase by one standard deviation ($6,400 at issuance compared to $7,680 at the testing price) and negative $1,344 at the testing price that represents a decrease by one standard deviation ($6,400 at issuance compared to $5,056 at the testing price).

(iv) FI then determines the absolute value of the difference between the change in value of the initial hedge and the Contract at the testing price that represents an increase by one standard deviation and a decrease by one standard deviation. Increased by one standard deviation, the absolute value of the difference is $720 ($2,000 − $1,280); decreased by one standard deviation, the absolute value of the difference is $244 (negative $1,100 minus negative $1,344). FI determines that there is a 52% chance that the price of Stock X will have increased in value when the Contract matures and a 48% chance that the price of Stock X will have decreased in value at that time. FI multiplies the absolute value of the difference between the change in value of the initial hedge and the Contract at the testing price that represents an increase by one standard deviation by 52%, which equals $374.40. FI multiplies the absolute value of the difference between the change in value of the initial hedge and the Contract at the testing price that represents a decrease by one standard deviation by 48%, which equals $117.12. FI adds these two numbers and divides by the number of shares that constitute the initial hedge to determine that the transaction calculation is 7.68 ((374.40 plus 117.12) divided by 64).

(v) FI then performs the same calculation with respect to the simple contract benchmark, which is a one-year call option that references one share of Stock X, settles on the same date as the Contract, and has a delta of 0.8. The one-year call option has a strike price of $79 and has a cost (the purchase premium) of $22. The initial hedge for the one-year call option is 0.8 shares of Stock X.

(vi) FI first determines that the change in value of the simple contract benchmark is $19.05 if the testing price is increased by one standard deviation ($22.00 at issuance to $41.05 at the testing price) and negative $20.95 if the testing price is decreased by one standard deviation ($22.00 at issuance to $1.05 at the testing price). Second, FI determines that the change in value of the initial hedge is $16.00 at the testing price that represents an increase by one standard deviation ($80 at issuance to $96 at the testing price) and negative $16.80 at the testing price that represents a decrease by one standard deviation ($80.00 at issuance to $63.20 at the testing price).

(vii) FI determines the absolute value of the difference between the change in value of the initial hedge and the one-year call option at the testing price that represents an increase by one standard deviation is $3.05 ($16.00 minus $19.05). FI next determines the absolute value of the difference between the change in value of the initial hedge and the option at the testing price that represents a decrease by one standard deviation is $4.15 (negative $16.80 minus negative $20.95). FI multiplies the absolute value of the difference between the change in value of the initial hedge and the option at the testing price that represents an increase by one standard deviation by 52%, which equals $1.586. FI multiplies the absolute value of the difference between the change in value of the initial hedge and the option at the testing price that represents a decrease by one standard deviation by 48%, which equals $1.992. FI adds these two numbers and divides by the number of shares that constitute the initial hedge to determine that the benchmark calculation is 4.473 ((1.586 plus 1.992) divided by .8).

(viii) FI concludes that the Contract is not a section 871(m) transaction because the transaction calculation of 7.68 exceeds the benchmark calculation of 4.473.

(i) through (p) [Reserved]. For further guidance, see § 1.871–15(i) through (p).

(q) *Dividend and dividend equivalent payments to a qualified derivatives dealer*—(1) *In general.* Except as otherwise provided in this paragraph (q), a qualified derivatives dealer described in § 1.1441–1(e)(6) that receives a dividend or the payment of a dividend equivalent (within the meaning of paragraph (i) of this section) in its dealer capacity will not be liable for tax under section 871 or section 881 provided that the qualified derivatives dealer complies with its obligations under the qualified intermediary agreement described in §§ 1.1441–1(e)(5) and 1.1441–1(e)(6). If a qualified derivatives dealer receives a dividend or dividend equivalent payment on or determined by reference to an underlying security and the offsetting dividend equivalent payment the qualified derivatives dealer is contractually obligated to make on the same underlying security is less than the dividend and dividend equivalent amount received (including when the qualified derivatives dealer is not contractually obligated to make an offsetting dividend equivalent payment), the qualified derivatives dealer is liable for tax under section 871 or section 881 for the difference. For purposes of this paragraph (q), a dividend or dividend equivalent is not treated as received by a qualified derivatives dealer acting in its dealer capacity if the dividend or dividend equivalent is received by the qualified derivatives dealer acting as a proprietary trader. Transactions properly reflected in a qualified derivatives dealer's dealer book are presumed to be held by a dealer in its dealer capacity for purposes of this paragraph (q).

(2) *Examples.* The following examples illustrate the rules of this paragraph (q):

Example 1. Forward contract entered into by a foreign dealer. (i) *Facts.* FB is a foreign bank that is a qualified intermediary that acts as a qualified derivatives dealer. On April 1, Year 1, FB enters into a cash settled forward contract initiated by a foreign customer (Customer) that entitles Customer to receive from FB all of the appreciation and dividends on 100 shares of Stock X, and obligates Customer to pay FB any depreciation on 100 shares of Stock X, at the end of three years. FB hedges the forward contract by entering into a total return swap contract with a domestic broker (U.S. Broker) and maintains the swap contract as a hedge for the duration of the forward contract. The swap contract entitles FB to receive an amount equal to all of the dividends on 100 shares of Stock X and obligates FB to pay an amount referenced to a floating interest rate each quarter, and also entitles FB to receive from or pay to U.S. Broker, as the case may be, the difference between the value of 100 shares of Stock X at the inception of the swap and the value of 100 shares of Stock X at the end of 3 years. FB provides valid documentation to U.S. Broker that FB will receive payments under the swap contract in its capacity as a qualified derivatives dealer, and FB contemporaneously enters both the swap contract with U.S. Broker and the forward contract with Customer on its dealer books. Stock X pays a quarterly dividend of $0.25 per share.

(ii) *Application of rules.* FB is a long party on a delta one contract (the total return swap) and a short party on a delta one contract (the forward contract with Customer). U.S. Broker is not obligated to withhold on the dividend equivalent payments to FB on the swap contract that are referenced to Stock X dividends, however, because U.S. Broker has received valid documentation that it may rely upon to treat the payment as made to FB acting as a qualified derivatives dealer. Similarly, FB is not obligated to pay tax on the payments it receives from U.S. Broker referenced to Stock X dividends because at the time it received the payments FB was contractually obligated to make fully offsetting dividend equivalent payments as the short party with respect to 100 shares of Stock X to Customer. FB is required to withhold on dividend equivalent payments to Customer on the forward contract in accordance with § 1.1441–2(e)(8).

Example 2. At-the-money option contract entered into by a foreign dealer. (i) *Facts.* The facts are the same as Example 1, but customer purchases from FB an at-the-money call option on 100 shares of Stock X with a term of one year. The call option has a delta of 0.5 and FB hedges the call option by purchasing 50 shares of Stock X, which are held in an account with U.S. Broker, who also acts as paying agent.

(ii) *Application of rules.* FB is a long party on 50 shares of Stock X and a short party on an option. Because the option has a delta of less than 0.8 on the date it was issued, it is not a section 871(m) transaction. U.S. Broker is not obligated to withhold on the Stock X dividends paid to FB because U.S. Broker has received valid documentation that it may rely upon to treat the dividends as paid to FB acting as a qualified derivatives dealer. FB is liable for tax under section 871 or section 881 on the Stock X dividends it receives from U.S. Broker, however, because at the time it received the dividends FB was not contractually obligated to make an offsetting dividend equivalent payment to Customer. FB is not required to make an offsetting dividend equivalent payment to Customer because the option has a delta of 0.5; therefore, it is not a section 871(m) transaction.

Example 3. In-the-money option contract entered into by a foreign dealer. (i) *Facts.* The facts are the same as Example 2, but Customer purchases from FB an in-the-money call option on 100 shares of Stock X with a term of one year. The call option has a delta of 0.8 and FB hedges the call option by purchasing 80 shares of Stock X, which are held in an account with U.S. Broker, who also acts as paying agent. The price of Stock X declines substantially and the option lapses unexercised.

(ii) *Application of rules.* FB is a long party on 80 shares of Stock X and a short party on an option. Because the option has a delta of 0.8 on the date it was issued, it is a section 871(m) transaction. U.S. Broker is not obligated to withhold on the Stock X dividends paid to FB because U.S. Broker has received valid documentation that it may rely upon to treat the dividends as paid to FB acting as a qualified derivatives dealer. Similarly, FB is not obligated to pay tax on the Stock X dividends it receives from U.S. Broker to the extent that FB is contractually obligated to make offsetting dividend equivalent payments as the short party to Customer. FB is required to withhold on dividend equivalent payments to Customer on the option contract in accordance with § 1.1441–2(e)(8). FB is also liable for tax under section 871 or section 881 on Stock X dividends, if any, that exceed the dividend equivalent payment to Customer.

(r)(1) through (3) [Reserved]. For further guidance, see § 1.871–15(r)(1) through (3).

(4) *Effective/applicability date.* This section applies to payments made on or after January 1, 2017.

(s) *Expiration date.* This section expires September 17, 2018.

■ **Par. 5.** Section 1.1441–1 is amended by:

■ 1. Redesignating paragraph (b)(4)(xxi) as (b)(4)(xxiv).

■ 2. Adding paragraphs (b)(4)(xxi) through (xxiii).

■ 3. Adding new paragraphs (e)(3)(ii)(E) and (6).

■ 4. Adding new paragraph (f)(4).

The additions read as follows:

§ 1.1441–1 Requirement for the deduction and withholding of tax on payments to foreign persons.

(b) * * *

(4) * * *

(xxi) Amounts paid with respect to a notional principal contract described in § 1.871–15(a)(7), an equity-linked instrument described in § 1.871–15(a)(4), or a securities lending or sale-repurchase transaction described in § 1.871–15(a)(13) are exempt from withholding under section 1441(a) as dividend equivalents under section 871(m) if the transaction is not a section 871(m) transaction within the meaning of § 1.871–15(a)(12), if the transaction is subject to the exception described in § 1.871–15(k), or if the payment is not a dividend equivalent pursuant to § 1.871–15(c)(2). However, the amounts may be subject to withholding under section 1441(a) if they are subject to tax under any section other than section 871(m). For purposes of this withholding exemption, it is not necessary for the payee to provide documentation establishing that a notional principal contract or equity-linked instrument has a delta (as described in § 1.871–15(g)) that is less than 0.80 or does not have substantial equivalence (as defined in § 1.871–15(h)) with the underlying security. For purposes of the withholding exemption regarding corporate acquisitions described in § 1.871–15(k), the exemption only applies if the long party furnishes, under penalties of perjury, a written statement to the withholding agent certifying that it satisfies the requirements of § 1.871–15(k).

(xxii) Certain payments to qualified derivatives dealers (as described in paragraph (e)(6) of this section). For purposes of this withholding exemption, the qualified derivatives dealer must furnish to the withholding agent the documentation described in paragraph (e)(3)(ii) of this section. A withholding agent that makes a payment of a dividend or a divided equivalent to a qualified intermediary that is acting as a qualified derivatives dealer is not required to withhold on the payment if the withholding agent can reliably associate the payment with a valid qualified intermediary withholding certificate as described in paragraph (e)(3)(ii) of this section, including the certification described in paragraph (e)(3)(ii)(E).

(xxiii) Amounts paid with respect to a potential section 871(m) transaction that is only a section 871(m) transaction as a result of applying § 1.871–15(n) to treat certain transactions as combined transactions, if the withholding agent is able to rely on one or more of the presumptions provided in § 1.871–15(n)(3)(i) or (ii) (applying those paragraphs whether or not the withholding agent is a short party by substituting ''withholding agent'' for ''short party''), and the withholding agent does not otherwise have actual knowledge that the long party (or a related person within the meaning of section 267(b) or section 707(b)) entered into the potential section 871(m) transaction in connection with any other potential section 871(m) transactions. The ability of one or more withholding agents to rely on the presumptions provided in section 1.871–15(n)(3) does not affect the withholding tax obligations or liability of any party to the transaction that cannot rely on the presumptions. Notwithstanding the withholding exemption provided to the withholding agent in this paragraph (b)(4)(xxii), the long party may still be liable for tax on dividend equivalent amounts with respect to such combined transactions under section 871(m).

(e)(3)(ii)(E) [Reserved]. For further guidance, see § 1.1441–1T(e)(3)(ii)(E).

(6) *Qualified derivatives dealers.* [Reserved]. For further guidance, see § 1.1441–1T(e)(6).

(f) * * *

(4) *Effective/applicability date.* Paragraphs (b)(4)(xxi) through (b)(4)(xxiii) of this section, and paragraphs (e)(3)(ii)(E) and (e)(6) of this section apply to payments made on or after September 18, 2015.

■ **Par. 6.** Section 1.1441–1T is amended by:

■ 1. Redesignating paragraph (e)(3)(ii)(E) as paragraph (e)(3)(ii)(F).

■ 2. Adding new paragraphs (e)(3)(ii)(E) and (e)(6).

■ 3. Revising paragraph (e)(5)(i).

■ 4. Amending paragraph (f)(3) by removing ''This section'' and adding in its place ''Except for paragraphs (e)(3)(ii)(E) and (e)(6), this section'' and adding a third sentence.

■ 5. Amending paragraph (g) by removing ''The applicability'' and adding in its place ''Except for paragraphs (e)(3)(ii)(E) and (e)(6), the applicability'' and adding a third sentence.

§ 1.1441–1T Requirement for the deduction and withholding of tax on payments to foreign persons (temporary).

(e) * * *

(3) * * *

(ii) * * *

(E) In the case of dividends or dividend equivalents received by a qualified intermediary acting as a qualified derivatives dealer, a certification that the qualified intermediary meets the requirements to act as a qualified derivatives dealer as further described in paragraph (e)(6) of this section and that the qualified derivatives dealer assumes primary withholding and reporting responsibilities under chapters 3, 4, and 61, and section 3406 with respect to any dividend equivalent payments;

(5) *Qualified intermediaries*—(i) *In general.* A qualified intermediary, as defined in paragraph (e)(5)(ii) of this section, may furnish a qualified intermediary withholding certificate to a withholding agent. The withholding certificate provides certifications on behalf of other persons for the purpose of claiming and verifying reduced rates of withholding under section 1441 or 1442 and for the purpose of reporting and withholding under other provisions of the Internal Revenue Code, such as the provisions under chapter 61 and section 3406 (and the regulations under those provisions). Furnishing such a certificate is in lieu of transmitting to a withholding agent withholding certificates or other appropriate documentation for the persons for whom the qualified intermediary receives the payment, including interest holders in a qualified intermediary that is fiscally transparent under the regulations under section 894. Although the qualified intermediary is required to obtain withholding certificates or other appropriate documentation from beneficial owners, payees, or interest holders pursuant to its agreement with the IRS, it is generally not required to attach such documentation to the intermediary withholding certificate. Notwithstanding the preceding sentence, a qualified intermediary must provide a withholding agent with the Forms W–9, or disclose the names, addresses, and taxpayer identifying numbers, if known, of those U.S. non-exempt recipients for whom the qualified intermediary receives reportable amounts (within the meaning of paragraph (e)(3)(vi) of this section) to the extent required in the qualified intermediary's agreement with the IRS. When a qualified intermediary is acting as a qualified derivatives dealer, the withholding certificate entitles a withholding agent to make payments of dividend equivalents and dividends to the qualified derivatives dealer free of withholding. Paragraph (e)(6) of this section contains detailed rules prescribing the circumstances in which a qualified intermediary can act as a qualified derivatives dealer. A person may claim qualified intermediary status before an agreement is executed with the IRS if it has applied for such status and the IRS authorizes such status on an interim basis under such procedures as the IRS may prescribe.

(6) *Qualified derivatives dealers*—(i) *In general.* To act as a qualified derivatives dealer under a qualified intermediary agreement, a qualified intermediary must be an eligible entity as described in paragraph (e)(6)(ii) of this section and, in accordance with the qualified intermediary agreement, must—

(A) Furnish to a withholding agent a qualified intermediary withholding certificate (described in paragraph (e)(3)(ii) of this section) that indicates that the qualified intermediary is a qualified derivatives dealer with respect to the applicable dividends and dividend equivalent payments;

(B) Agree to assume the primary withholding and reporting responsibilities, including the documentation provisions under chapters 3, 4, and 61, and section 3406, the regulations under those provisions, and other withholding provisions of the Internal Revenue Code, on all dividends and dividend equivalents that it receives and makes in its dealer capacity. For this purpose, a qualified derivatives dealer is required to obtain a withholding certificate or other appropriate documentation from each counterparty to whom the qualified derivatives dealer pays a dividend equivalent. The qualified derivatives dealer is also required to determine whether a payment it makes to a counterparty is, in whole or in part, a dividend equivalent;

(C) Agree to remain liable for tax under section 871 and section 881 on any dividend or payment of a dividend equivalent (within the meaning of § 1.871–15(i)) it receives in its dealer capacity to the extent that the offsetting dividend equivalent payment on an underlying security the qualified derivatives dealer is contractually obligated to make is less than the dividend and dividend equivalent amount the qualified derivatives dealers received on or with respect to the same underlying security (including when the qualified derivatives dealer is not contractually obligated to make an offsetting dividend equivalent payment); and

(D) Comply with the compliance review procedures applicable to a qualified intermediary that acts as a qualified derivatives dealer under a qualified intermediary agreement, which will specify the time and manner in which a qualified derivatives dealer must:

(*1*) Certify to the IRS that it has complied with the obligations to act as a qualified derivatives dealer (including its performance of a periodic review applicable to a qualified derivatives dealer);

(*2*) Report to the IRS the dividend equivalent payments that it made and the dividends and dividend equivalent amounts received in determining offsetting payments (as described in § 1.871–15(q)(1)); and

(*3*) Respond to inquiries from the IRS about obligations it has assumed as a qualified derivatives dealer in a timely manner.

(ii) *Definition of eligible entity.* An eligible entity is a qualified intermediary that is—

(A) A dealer in securities subject to regulatory supervision as a dealer by a governmental authority in the jurisdiction in which it was organized or operates; or

(B) A bank subject to regulatory supervision as a bank by a governmental authority in the jurisdiction in which it was organized or operates or an entity that is wholly-owned by a bank subject to regulatory supervision as a bank by a governmental authority in the jurisdiction in which it was organized or operates and that—

(*1*) Issues potential section 871(m) transactions to customers; and

(*2*) Receives dividends with respect to stock or dividend equivalent payments pursuant to potential section 871(m) transactions that hedge potential section 871(m) transactions that it issued.

(iii) *Crediting prior withholding to a subsequent dividend equivalent payment.* [Reserved].

(f)(3) * * * Paragraphs (e)(3)(ii)(E) and (e)(6) apply beginning September 18, 2015.

(g) * * * Paragraphs (e)(3)(ii)(E) and (e)(6) of this section expire September 17, 2018.

■ **Par. 7.** Section 1.1441–2 is amended by adding paragraph (e)(8) and adding a sentence to the end of paragraph (f) to read as follows:

§ 1.1441–2 Amounts subject to withholding.

* * * * *

(e) * * *

(8) *Payments of dividend equivalents*—(i) *In general.* A payment of a dividend equivalent is not considered to be made until the later of when—

(A) The amount of a dividend equivalent is determined as provided in § 1.871–15(j)(2), and

(B) A payment occurs with respect to the section 871(m) transaction.

(ii) *Payment.* For purposes of paragraph (e)(8) of this section, a payment occurs with respect to a section 871(m) transaction when—

(A) Money or other property is paid to or by the long party;

(B) In the case of a section 871(m) transaction described in § 1.871–15(i)(3), a payment is treated as being made at the end of the applicable calendar quarter; or

(C) The long party sells, exchanges, transfers, or otherwise disposes of the section 871(m) transaction (including by settlement, offset, termination, expiration, lapse, or maturity).

(iii) *Premiums and other upfront payments.* When a long party pays a premium or other upfront payment to the short party at the time a section 871(m) transaction is issued, the premium or other upfront payment is not treated as a payment for purposes of paragraph (e)(8)(ii)(A) of this section.

* * * * *

(f) * * * Paragraph (e)(8) of this section applies to payments made on or after September 18, 2015.

■ **Par. 8.** Section 1.1441–3 is amended by:

■ 1. Adding a second sentence to paragraph (h)(1).

■ 2. Redesignating paragraph (h)(2) as (h)(3) and revising newly redesignated paragraph (h)(3).

■ 3. Adding new paragraph (h)(2).

The additions and revisions read as follows:

§ 1.1441–3 Determination of amounts to be withheld.

* * * * *

(h) * * *

(1) * * * Withholding is required on the amount of the dividend equivalent calculated under § 1.871–15(j).

(2) *Reliance by withholding agent on reasonable determinations.* For purposes of determining whether a payment is a dividend equivalent and the timing and amount of a dividend equivalent under section 871(m), a withholding agent may rely on the information received from the party to the transaction that is required (as provided in § 1.871–15(p)) to make those determinations, unless the withholding agent knows or has reason to know that the information is incorrect. When a withholding agent fails to withhold the required amount because the party described in § 1.871–15(p) fails to reasonably determine or timely provide information regarding whether a transaction is a section 871(m) transaction, the timing and amount of any dividend equivalent, or any other information required to be provided pursuant to § 1.871–15(p), and the withholding agent relied, absent actual knowledge to the contrary, on that party's determination or did not timely receive required information, then the failure to withhold is imputed to the party required to make the determinations described in § 1.871–15(p). In that case, the IRS may collect any underwithheld amount from the party to the transaction that was required to make the determinations described in § 1.871–15(p) or timely provide the information and subject that party to applicable interest and penalties as if the party were a withholding agent with respect to the payment of the dividend equivalent made pursuant to the section 871(m) transaction.

(3) *Effective/applicability date.* Except for the first sentence of paragraph (h)(1), this paragraph (h) applies to payments made on or after September 18, 2015. The first sentence of paragraph (h)(1) of this section, applies to payments made on or after January 23, 2012.

* * * * *

■ **Par. 9.** Section 1.1441–7 is amended by:

■ 1. Adding *Example 7* to paragraph (a)(3).

■ 2. Adding a second sentence to paragraph (a)(4).

The additions read as follows:

§ 1.1441–7 General provisions relating to withholding agents.

(a) * * *

(3) * * *

Example 7. CO is a domestic clearing organization. CO serves as a central counterparty clearing and settlement service provider for derivatives exchanges in the United States. CB is a broker organized in Country X, a foreign country, and a clearing member of CO. CB is a nonqualified intermediary, as defined in § 1.1441–1(c)(14). FC is a foreign corporation that has an investment account with CB. FC instructs CB to purchase a call option that is a specified ELI (as described in § 1.871–15(e)). CB effects the trade for FC on the exchange. The exchange matches FC's order with an order for a written call option with the same terms. The exchange then sends the matched trade to CO, which clears the trade. CB and the clearing member representing the call option seller settle the trade with CO. Upon receiving the matched trade, the option contracts are novated and CO becomes the counterparty to CB and the counterparty to the clearing member representing the call option seller. To the extent that there is a dividend equivalent with respect to the call option, both CO and CB are withholding agents as described in paragraph (a)(1) of this section.

(4) * * * *Example 7* of paragraph (a)(3) of this section applies to payments made on or after September 18, 2015.

* * * * *

■ **Par. 10.** Section 1.1461–1 is amended by:

■ 1. Redesignating paragraphs (c)(2)(i)(N) as (c)(2)(i)(O) and (c)(2)(i)(M) as (c)(2)(i)(N).

■ 2. Adding paragraph (c)(2)(i)(M).

■ 3. Redesignating paragraph (c)(2)(ii)(K) as (c)(2)(ii)(L) and redesignating paragraph (c)(2)(ii)(J) as (c)(2)(ii)(K)

■ 4. Adding paragraph (c)(2)(ii)(J).

§ 1.1461–1 Payments and returns of tax withheld.

* * * * *

(c) * * *

(2) * * *

(i) * * *

(M) Any dividend or any payment that references the payment of a dividend from an underlying security pursuant to a securities lending or sale-repurchase transaction paid to a qualified derivatives dealer even when the withholding agent is not required to withhold on the payment pursuant to § 1.1441–1(b)(4)(xxi), (xxii), or (xxiii);

* * * * *

(ii) * * *

(J) Except as provided in § 1.1461–1(c)(2)(i)(M), any payment to a qualified derivatives dealer when the withholding agent is not required to withhold on the payment pursuant to § 1.1441–1(b)(4)(xxi), (xxii), or (xxiii);

* * * * *

■ **Par. 11.** Section 1.1473–1 is amended by:

■ 1. Adding new paragraph (a)(4)(viii).

■ 2. Adding a sentence to the end of paragraph (f).

The additions read as follows:

§ 1.1473–1 Section 1473 definitions.

(a) * * *

(4) * * *

(viii) *Certain dividend equivalents.* Amounts paid with respect to a notional principal contract described in § 1.871–

15(a)(7), an equity-linked instrument described in § 1.871–15(a)(4), or a securities lending or sale-repurchase transaction described in § 1.871–15(a)(13) that are exempt from withholding under section 1441(a) as dividend equivalents under section 871(m) if the transaction is not a section 871(m) transaction within the meaning of § 1.871–15(a)(12), if the transaction is subject to the exception described in § 1.871–15(k), or to the extent the payment is not a dividend equivalent pursuant to § 1.871–15(c)(2).

* * * * *

(f) * * * Paragraph (a)(4)(viii) of this section applies to payments made on or after September 18, 2015.

John Dalrymple,

Deputy Commissioner for Services and Enforcement.

Approved: July 20, 2015.

Mark J. Mazur,

Assistant Secretary of the Treasury (Tax Policy).

[FR Doc. 2015–21759 Filed 9–17–15; 8:45 am]

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